Distribution Integrity Management Program

Puget Sound Energy

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Section 1: Scope

This document is the written Distribution Integrity Management Plan (DIM Plan) for Puget Sound Energy (PSE). This DIM Plan in conjunction with the Continuing Surveillance Annual Report comprises PSE's Distribution Integrity Management Program (DIM Program) in accordance with the requirements of 49 CFR Part 192, Subpart P, Distribution Integrity Management Program.

The purpose of PSE's DIM Program is to enhance safety by identifying and reducing gas distribution pipeline integrity risks. PSE's DIM Program integrates reasonably available information about its pipelines, considers the likelihood of failure and the potential consequence of failure, identifies the appropriate mitigative measures, evaluates the effectiveness of these measures, and updates the mitigative measures as appropriate. The implementation of this DIM Plan includes ongoing processes that will continue to drive improvements in the DIM Program to enhance the integrity of PSE's gas distribution system.

DIM Plan

This written DIM Plan specifies procedures for developing and implementing the following elements as required by 49 CFR Part 192, Subpart P, Distribution Integrity Management Program (DIMP):

- Gather System Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Evaluate and Improve DIM Plan and Program
- Report results

This written plan also documents the relatively static elements of PSE's DIM Program in the Appendices. Relatively static elements include historical system design, construction, operation and maintenance practices as well as mitigative measures that have already been implemented.

Continuing Surveillance Annual Report

The Continuing Surveillance Annual Report documents the more dynamic elements of PSE's DIM Program. It also documents that PSE has performed the procedures and processes required by the DIM Plan. This includes reporting on system performance measures, conducting a broad review of system performance data, and providing a detailed discussion of what this data indicates. This includes validation and confirmation of previously identified trends and the identification of emerging trends; a description of plans to initiate new proactive measures; any plans to continue, modify or add additional and accelerated actions; and provides a format for tracking and reporting on subsequent progress. If additional or enhanced measures are needed, these plans will be incorporated in the budget process for funding for the following calendar year and integrated into the DIM Plan as appropriate.

PSE's DIM Program approach promotes continuous improvement in pipeline safety. This is accomplished by continually working to improve system and risk knowledge, implementing measures to mitigate risks, and evaluating these measures to validate their effectiveness, and revising these mitigative measures as necessary based on this evaluation.

Section 2: Responsibilities

The *Manager Gas System Integrity* has overall responsibility to assure that processes are implemented by the organization in accordance with this DIM Plan and associated regulatory requirements. The *Manager Gas System Integrity* may delegate some or all of these responsibilities to others within the organization.

Additional responsibilities for implementing specific mitigative measures are documented in the appropriate manual including the Gas Operating Standard, Gas Field Procedure, and Emergency Response Plans.

Some of the specific tasks that the *Manager Gas System Integrity* is responsible for are listed in Table 1, DIM Program Tasks.

Table 1-1. DIM Program Tasks

Role / Responsibility	Recommended Timeframe for Updates
Overall Program Implementation and Oversight	Ongoing
Update the Continuing Surveillance Annual Report	Annually (by May 1)
Conduct and document review and updates to the DIM Plan and DIM Program	Annually (3rd quarter)
Determine DIM Program budget requirements and make associated Capital and Operation and Maintenance budget requests	Annually
Monitor completion of specific DIM Program projects and implementation of additional and accelerated actions	Ongoing
Maintain DIM Program Records and Files	Ongoing

Section 3: DIMP Processes

The DIM Program processes are documented in Appendix A. These processes illustrate how PSE implements the requirements of this DIM Plan.

Section 4: Definitions

(CFR 192.1001)

The terminology used in this DIM Plan is defined in Table 4-1. The "*" symbol adjacent to a listed term means the definition is identical to the definition in 49 CFR Part 192, Subpart P, Distribution Integrity Management Program. Any terms and definitions not listed below are defined in PSE's Gas Operating Standard (GOS) 2400.1000 Definitions.

Table 4-1. Terms and Definitions

Term	Definition
Additional and Accelerated Actions	Measures to reduce risks that exceed minimum code requirements.
Distribution Integrity Management (DIM) Plan	A written explanation of the mechanisms or procedures used to implement the DIM program and to ensure compliance with 49 CFR Part 192, Subpart P, Distribution Integrity Management Program.
Distribution Integrity Management (DIM) Program	An overall approach to ensure the integrity of the gas distribution system.
Excavation damage*	Any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.
Hazardous Leak*	A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.
Mitigative Measures	All measures that reduce risks including those required by the regulations as well as additional and accelerated actions.

Section 5: Knowledge of the Distribution System

(CFR 192.1007(a)(1), CFR 192.1007(a)(2), CFR 192.007(a)(3), and CFR 192.007(a)(5))

There are many components to system knowledge including the knowledge of the existing system, knowledge and data capture for new construction, and additional data to enhance the knowledge of the existing system. With this system knowledge, characteristics of the pipeline's design and operations and the environmental factors shall be identified as necessary to assess the applicable threats and risks to the gas distribution system.

Existing System Knowledge

This Plan divides existing system knowledge into two categories. These include historical and current design, construction, operation and maintenance practices which are relatively static as well as system statistics that are dynamic and change each year. Examples of dynamic data include the quantities of pipe of different vintages and materials that are in service in the system which is constantly changing.

The more static system knowledge shall be documented in Appendix B of the DIM Plan. This shall include historical and current design, construction, operation, and maintenance practices. This shall be based on information from readily available resources including historical purchase specifications, written standards and procedures, training manuals, DOT reports, and discussions with Subject Matter Experts (SME). This information shall be updated as additional data is found related to past practices and as current practices are updated.

The dynamic system knowledge shall be documented in the Continuing Surveillance Annual Report. This information is different from the data provided in Appendix B as it is updated annually to reflect the changing make-up of the distribution system. This report shall include the following information:

- The relative amounts of pipe by material, vintage, and facility type
- The miles of main operating within different pressure classes
- New and active leak trends
- Leak repair trends
- Failure analysis trends
- System condition report trends
- Federally reportable trends
- Third party damage prevention program trends

New Construction Knowledge

PSE shall capture and retain data on all new pipelines including where it is installed and the material which it is constructed in accordance with the requirements of Gas Operating Standard 2500.1700 As-Builts and Gas Operating Standard 2500.1800 D-4 Cards. PSE shall also capture O&M information in accordance with Gas Operating Standard 2500.0500 Maps and Records Requirements.

Future Data Capture to Enhance System Knowledge

Existing system knowledge and system performance data and trends shall be reviewed annually to determine whether additional information needs to be captured to increase system risk understanding and fill gaps due to missing, inaccurate, or incomplete records. The results of this review shall be documented in the Continuing Surveillance Annual Report.

If it is determined that additional information shall be captured or that improvements in data accuracy/integrity are needed, this requirement shall be documented in the Continuing Surveillance Annual Report. For additional data capture, this shall include documenting the type of additional data that is required, the plan to develop a process for gaining this information over time through normal activities, such as design, construction, operations or maintenance activities, or other targeted activities, the responsible department for developing and implementing the process, and target timeframes for implementing the process. For data accuracy improvements, this shall include documenting the data that needs to be more accurate, the department responsible for developing and implementing a plan to improve the data accuracy, and the target timeframes for implementing the improved process. Once the process is developed, the requirements and the process shall be documented in the Gas Operating Standards, Gas Field Procedures, or other appropriate manual.

Section 6: Threat Assessment and Identification

(CFR 192.1007(b))

This section of the Plan establishes the requirement to assess and identify existing and potential threats while considering reasonably available information.

Existing Threats

The Continuing Surveillance Annual Report shall annually re-assess the threats to PSE's gas distribution system using subject matter experts input as well as incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience. Based on the current assessment as documented in the Continuing Surveillance Annual Report, PSE has concluded that the following are threats to the distribution system:

- Corrosion
- Natural forces
- Excavation damage
- Other outside force damage
- Material, weld, or joint failure
- Equipment failure
- Incorrect operation

Additional analysis of sub-threats to the primary threats is discussed in the Section 7 Risk Evaluation and Prioritization.

Potential Threats

The Continuing Surveillance Annual Report shall include a review of system performance data and operational metrics to determine whether there are new or emerging threats that have not previously been identified. Any new or emerging threats or trends shall be evaluated and discussed in the Continuing Surveillance Annual Report. This will include an assessment of the likelihood of failure associated with the threat, the potential consequences of such a failure, and any additional or accelerated actions that shall be implemented to mitigate the threat.

In addition to this annual review, timely identification and remediation of individual issues that require immediate action is accomplished through processes established in Gas Operating Standard 2575.2700 Continuing Surveillance, Gas Operating Standard 2575.2800 Examining Buried Pipelines, and Gas Operating Standard 2625.1300 Leakage Action Program.

Section 7: Risk Evaluation and Prioritization

(CFR 192.1007(c))

PSE shall evaluate and prioritize the risks to PSE's distribution system. The results of this assessment are documented in Appendix C.

This risk evaluation and prioritization shall be based on subject matter experts input as well as design and construction information, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience. The evaluation and ranking of risk shall consider:

- Each applicable current and potential threat
- The likelihood of failure associated with each threat
- The potential consequences of such a failure
- The relevance of threats in one location to other areas
- Where a combination of threats exist on a pipeline segment that impacts the total risk of the individual segment

Appendix C also documents the detailed methodology for performing the risk evaluation and prioritization. This evaluation and ranking of risks shall be reviewed annually in conjunction with the Continuing Surveillance Annual Report review required by Section 10 Periodic Evaluation and Improvement. The review shall include any new risk knowledge, new or emerging threats, and new knowledge of factors that affect the risk posed by threats to the gas distribution pipeline and where they are relatively more important than other threats.

The risk evaluation shall be validated and shall confirm that the results agree with SME experience and system data. If the results do not agree, the risk evaluation shall be revised as appropriate. The Risk Evaluation and Prioritization Matrix shall be updated as necessary based on this review.

Section 8: Mitigative Measures and Additional and Accelerated Actions to Address Risks

(CFR 192.1007(d))

Based on the Risk Evaluation and Prioritization Matrix, PSE shall identify where additional and accelerated actions are required and shall specify the thresholds that require these additional and accelerated actions. This assessment shall include identifying where risk reduction measures are required to address individual threats as well as where a combination of threats exist and impact the total risk also requiring risk reduction measures. The results of this assessment shall be documented in the Continuing Surveillance Annual Report.

The mitigative measures currently implemented by PSE shall be documented in Appendix D Summary of Mitigative Measures. This table shall document each threat the measure is intended to mitigate and reference the document that details the specific requirements of the mitigative measure. Documents that specify additional and accelerated actions shall also specify when these measures are required to be taken.

These measures include those that are mandated by the 49 Code of Federal Regulations (CFR) Part 192 and Washington Administrative Code (WAC) Title 480 Utilities Transportation Commission as well as additional and accelerated actions PSE has identified and implemented to reduce risks and manage the integrity and reliability of the gas distribution system.

In addition to the Summary of Mitigative Measures, Appendix E Additional and Accelerated Actions further highlights critical practices and additional and accelerated actions that are currently reducing risks. These additional and accelerated actions are actions specified in existing manuals including the Gas Operating Standards and Gas Field Procedures and/or are best practices that have been adopted as PSE's company practices. These are listed to emphasize the actions that are beyond those required by the regulations and to facilitate the consideration of the DIM Program when any revisions are made to these existing practices.

Based on the Risk Evaluation and Prioritization Matrix, certain facilities with similar properties that have been identified as requiring additional and accelerated actions shall be risk ranked within its own population. This allows for more appropriate additional and accelerated actions to be identified to effectively mitigate risks within the certain facility. These facilities include bare steel, pre-1972 wrapped steel services, wrapped steel pipe, and older vintage PE pipe. The methodology used to risk rank the segments, the process for determining remedial action based on the risk ranking, and the corresponding additional and accelerated actions are documented in the Bare Steel Settlement Agreement and Appendix F. These risk models include those in the Bare Steel Replacement Program, the Wrapped Steel Service Assessment Program, the Wrapped Steel Pipe Mitigation Program, and the Older Vintage PE Mitigation Program.

Additional and accelerated actions that are being evaluated, are in development, or are in the process of implementation shall be documented in the Additional and Accelerated Actions section of the Continuing Surveillance Annual Report. This documentation shall include a description of the measure, the department responsible for evaluating or implementing the mitigative measure, and the target timeframes for completing the evaluation or implementation. Once the new or revised measure is implemented, the new requirement and associated processes shall be incorporated in future updates to appropriate documents such as the Gas Operating Standards, Gas Field Procedures, Distribution Integrity Management Plan, Design and Construction Manual, or appropriate manuals.

If the evaluation of an additional and accelerated action concludes that the candidate additional and accelerated action shall not be implemented or that other measures shall be taken or evaluated, documentation of the evaluation, the conclusion, and the basis for the conclusion shall be documented in the next update to the Continuing Surveillance Annual Report.

Section 9: Measure Performance, Monitor Results, and Evaluate Effectiveness

(CFR 192.1007(d) and CFR 192.1007(e)(1))

This section establishes the requirement to measure performance, monitor results and evaluate the effectiveness of the DIM Program. This includes evaluation of performance measures that are numerical and can be trended over time as well as a more subjective evaluation of the effectiveness of the Leak Management Program.

Performance Measures

The performance measures used to evaluate the effectiveness of PSE's DIM Program are specified below. The baselines for these measures shall be included in the Continuing Surveillance Report and shall be updated annually as necessary. This annual update shall also include a discussion of the trends these measures show, an assessment of the effectiveness of the measures implemented to address risks, whether any additional performance measures should be added to the DIM Plan, and whether any changes are needed to the mitigative measures. If additional performance measures are identified through this process, they shall be documented in the Continuing Surveillance Annual Report and incorporated in the next update to the DIM Plan.

Performance Measures:

1. The number of hazardous leaks either eliminated or repaired, categorized by cause
2. The number of excavation damages
3. The number of excavation tickets received
4. The number of leaks either eliminated or repaired, categorized by cause
5. The number of hazardous leaks either eliminated or repaired, categorized by material
6. Average response time to emergency odor or leak calls

Leak Management Program

PSE's Gas Operating Standard 2625.1100 Leak Survey Program requires self audits to be performed to evaluate the effectiveness of PSE's leak management program. A summary of the results of the audit shall be reported in the Continuing Surveillance Annual Report including whether any changes were identified to improve the effectiveness of the leak management program.

Section 10: Periodic Evaluation and Improvement

(CFR 192.1007(e)(1), CFR 192.1007(f), and CFR 192.1007(a)(4))

This section of the Plan requires periodic re-evaluation of both the DIM Plan and the DIM Program.

<u>DIM Plan</u>

This DIM Plan shall be reviewed annually and updated as appropriate based on this review. This review and update shall include:

- Ensuring the Section 2 Responsibilities is up-to-date based on current organizational structure

- Updating additional and accelerated actions that have been implemented since the last DIM Plan update or revisions to existing mitigative measures. This shall include adding the document specifying the requirements of the mitigative measure to the DIM Plan Appendix or referencing the appropriate document if it is incorporated into the Gas Operating Standard manual, Gas Field Procedure manual, or other appropriate manual

- Updating System Knowledge based on changes to current design, construction, operation and maintenance practices

- Updating System Knowledge as additional data is found related to past design, construction, operation and maintenance practices

- Incorporating new or revised risk knowledge based on the most recent Continuing Surveillance Annual Report. This includes but is not limited to any new or emerging threats, revisions to the risk evaluation and prioritization, new or revised mitigative measures, and any new performance measures

- Incorporating any other updates as needed to reflect changes to PSE's DIM Plan.

If there are no updates required, the date the review was completed and the name and signature of the person responsible for completing the review shall be recorded in the DIM Program files.

DIM Program

The effectiveness of the DIM Program shall be reviewed annually and documented in the Periodic Evaluation and Improvement section of the Continuing Surveillance Annual Report. This shall include:

1. Reviewing the results of the performance measures, results monitoring, and effectiveness evaluation required by Section 9. Based on this review, PSE shall determine whether or not the existing mitigative measures are effectively mitigating the risks they are intended to address, additional time is required to have sufficient data to make a determination, or different performance measure are required to make a determination.

2. Determining whether to continue, discontinue, accelerate, decelerate, modify, or add additional and accelerated actions or mitigative measures. The basis for this determination shall be documented in the Continuing Surveillance Annual Report.

3. Evaluating the threats and risks to PSE's entire distribution system, updating the Risk Evaluation and Prioritization Matrix and Risk Ranking/Replacement Programs as necessary, and considering the relevance of threats in one location to other areas.

4. Determining whether additional data gathering is required to improve risk knowledge per Section 5 Knowledge of Distribution System.

5. Evaluating the effectives of the leakage management program and identify steps to correct any deficiencies if they exist.

Section 11: Reporting

(CFR 192.1007(g), CFR 192.1009(a), and CFR 192.1009(b))

The following shall be reported:

1. The performance measures required by CFR 192.1007(e)(1) and the number of excess flow valves installed shall be reported in accordance with Gas Operating Standard 2425.2600 Distribution Integrity Management Program.

2. Information related to failure of mechanical fittings shall be reported in accordance with Gas Operating Standard 2425.2600 Distribution Integrity Management Program.

3. Additional reporting shall be performed in accordance with the requirements specified in the Risk Ranking/Replacement Programs in the Appendices to this Plan.

4. The Continuing Surveillance Annual Report shall be submitted to the WUTC by May 15th each year.

5. Updates to this DIM Plan shall be submitted to the WUTC by September 15th each year the Plan is updated.

Section 12: Record Keeping

(CFR 192.1011)

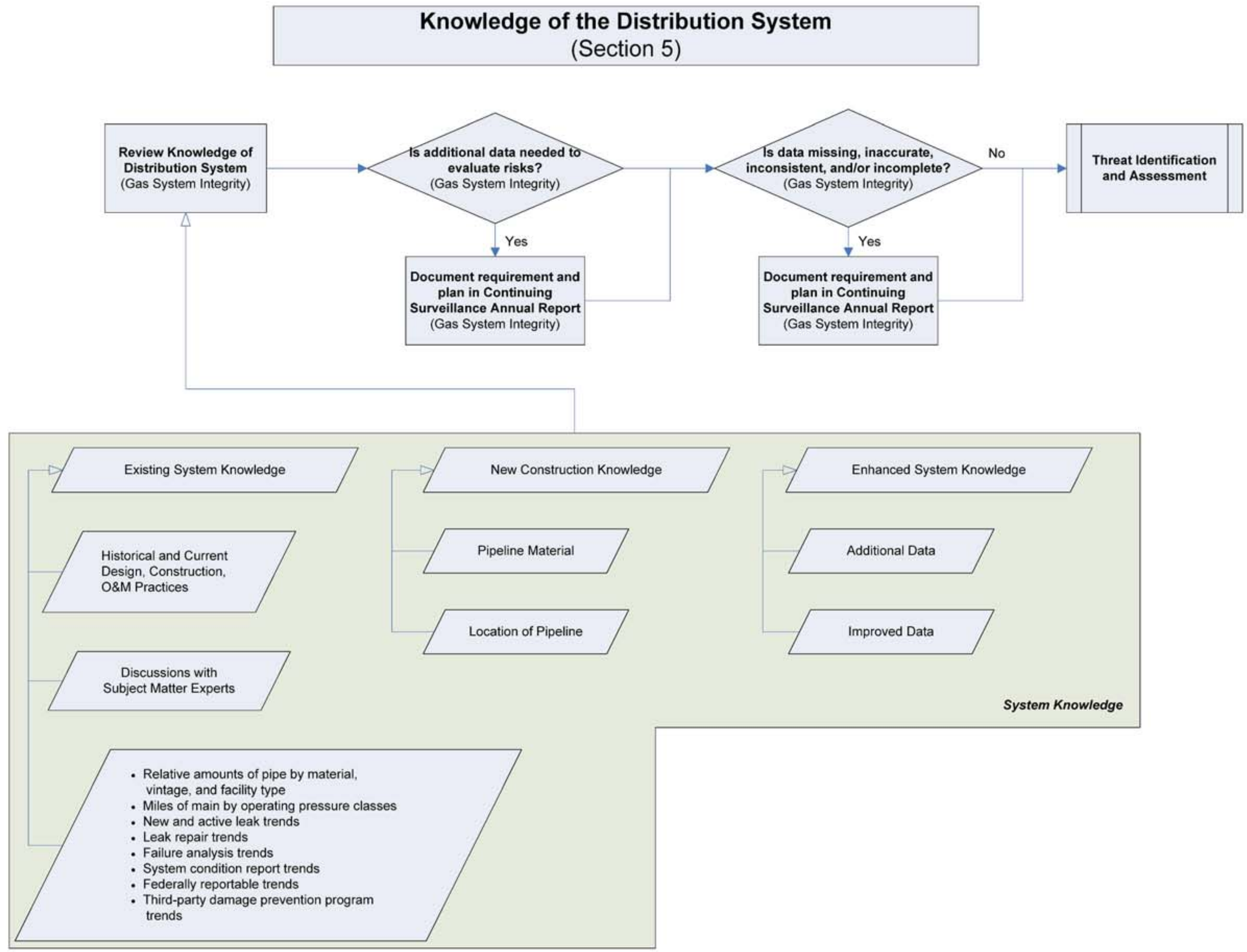
The following records must be maintained in the DIM Program files for ten years:

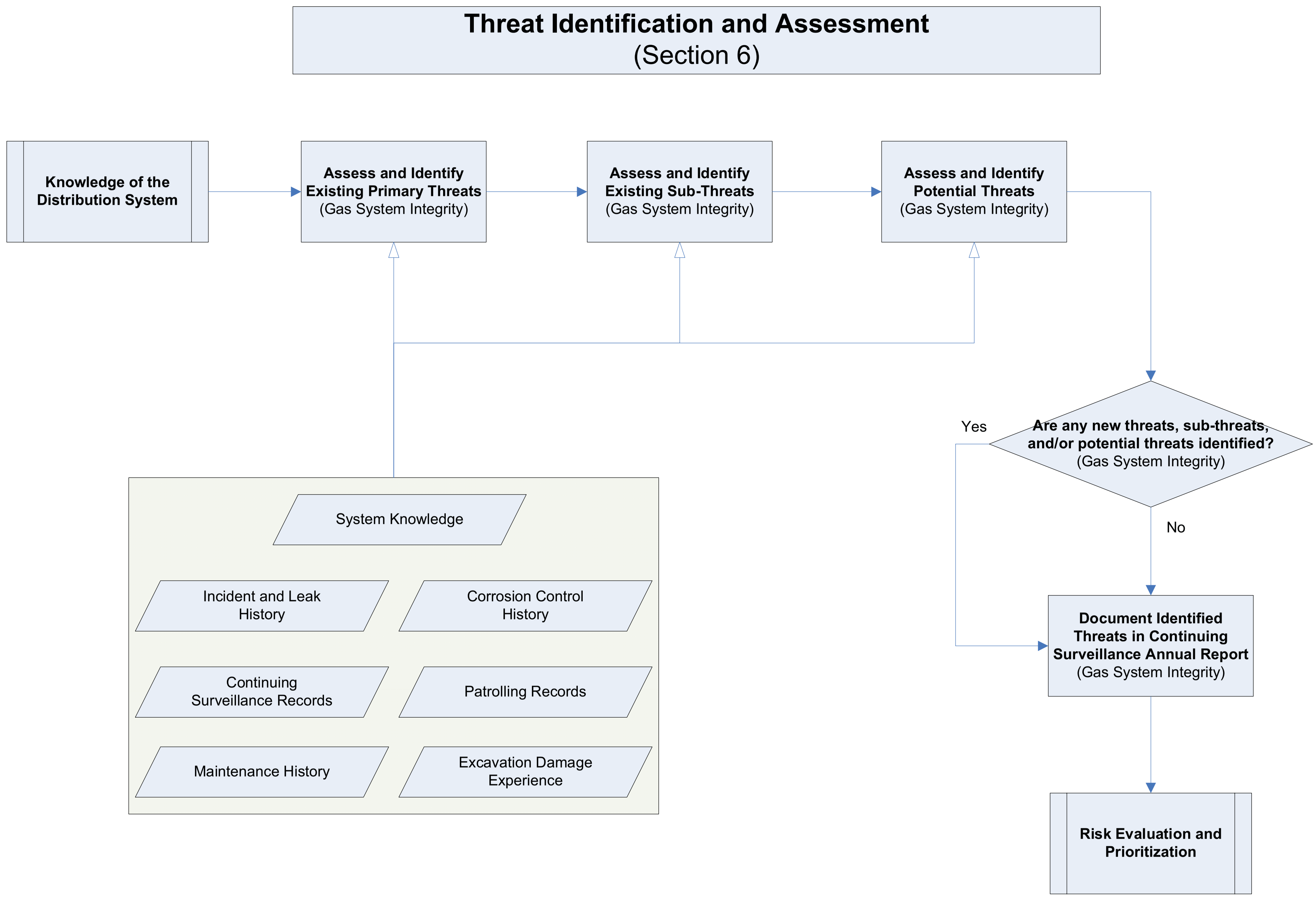
- Copies of the current and previous written DIM Plans
- Proof of annual review of the DIM Plan if no updates are made to the plan in any calendar year
- Copies of the current and previous Continuing Surveillance Annual Report
- Records of data required to be collected to calculate performance measures
- Mechanical Fitting Failure Reports
- Excavation Damage Prevention Annual Reports
- Material Failure and Construction Defect Reports
- Documentation of Annual DIM Program and DIM Plan Reviews
- Annual Reports to PHMSA (as required by §191.11) and WUTC

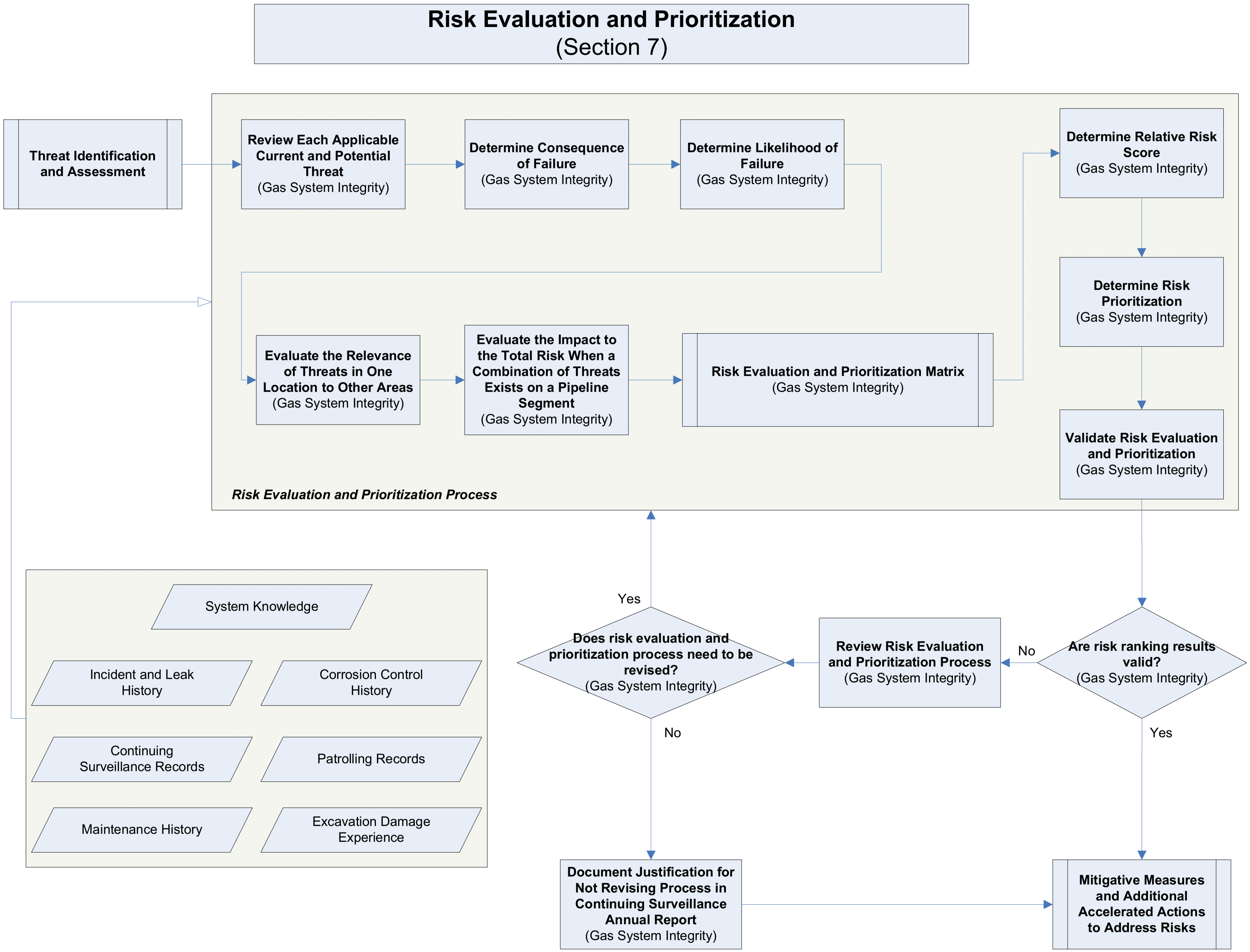
Distribution Integrity Management Program

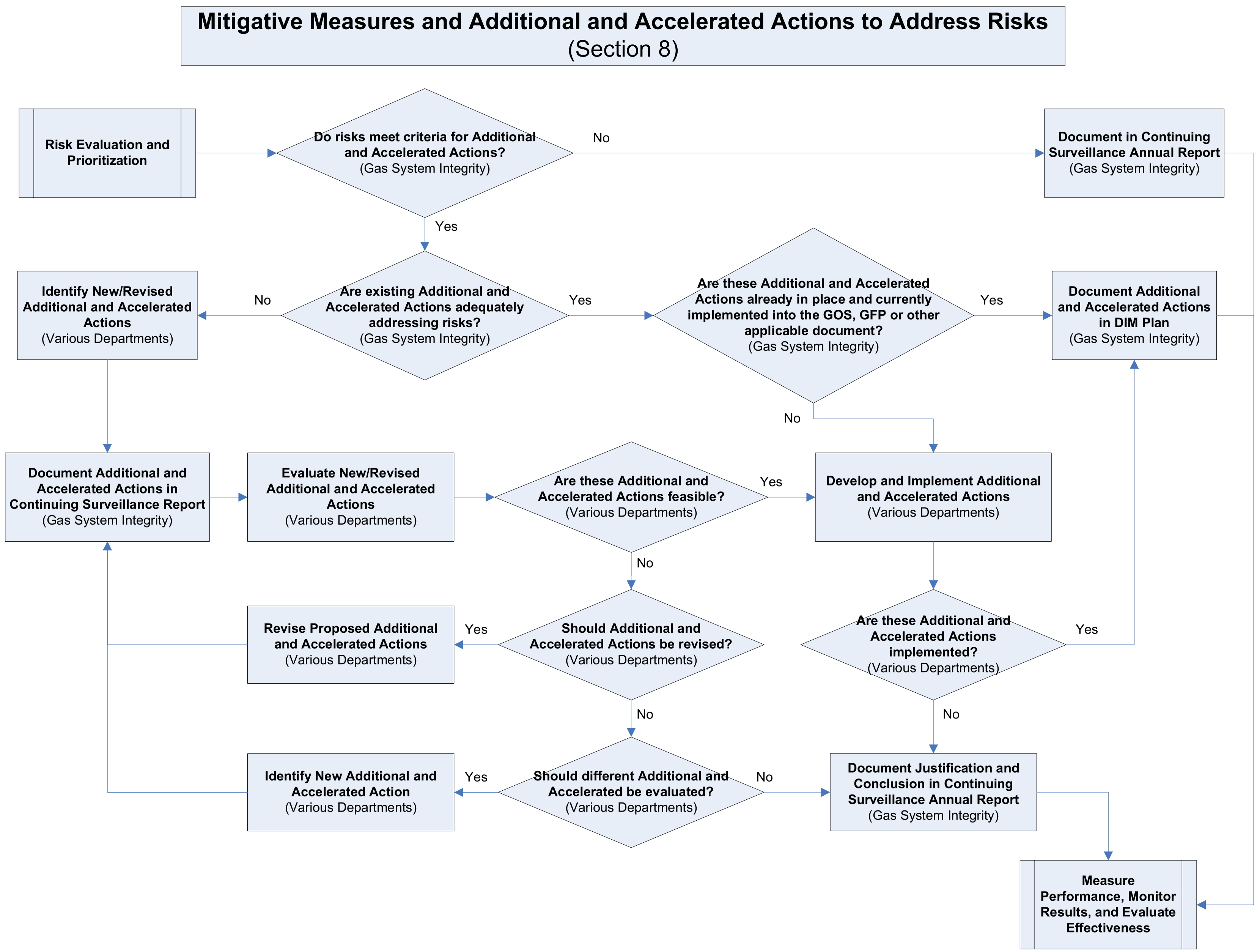
Appendix

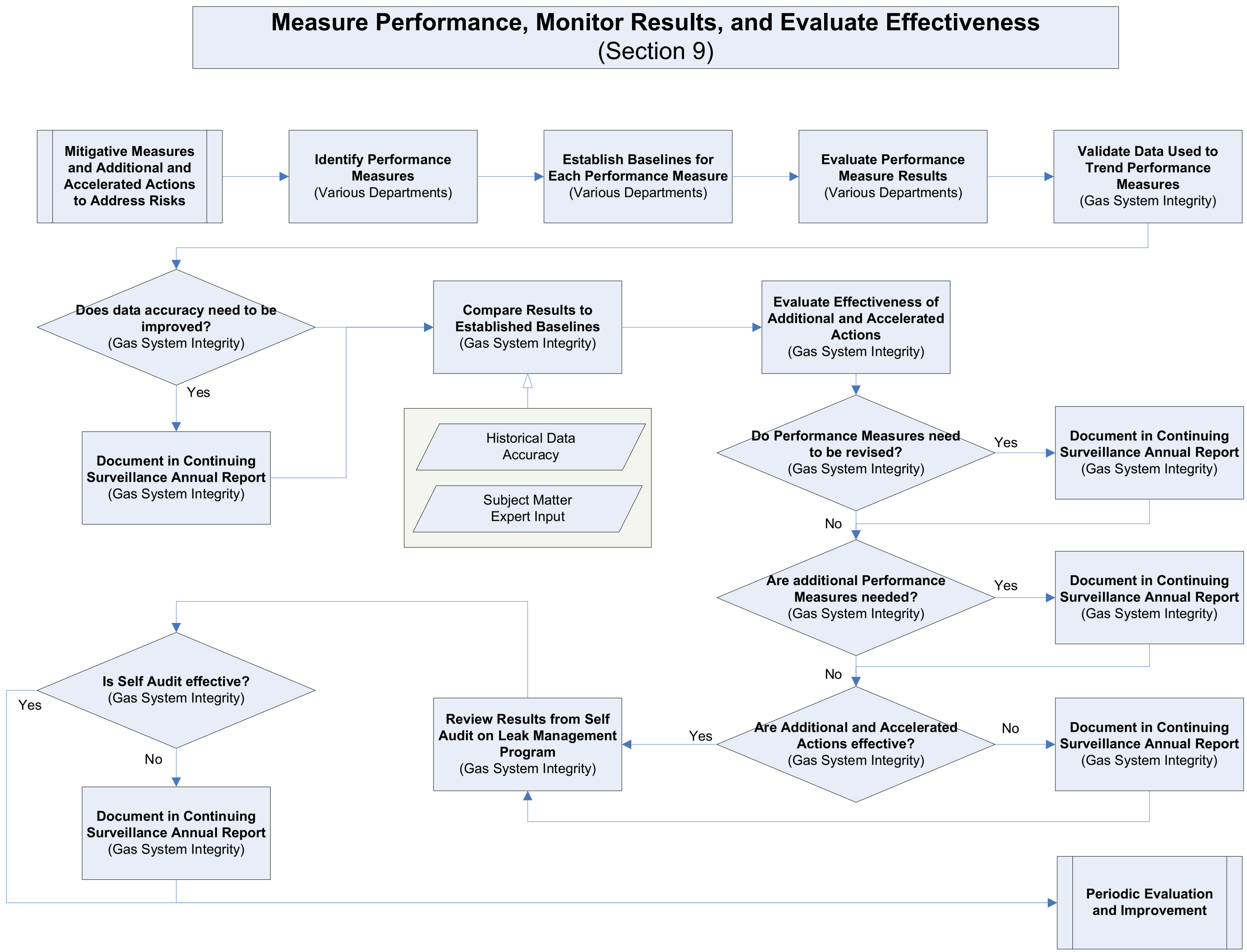
Appendix A: DIM Program Process Flow Diagrams

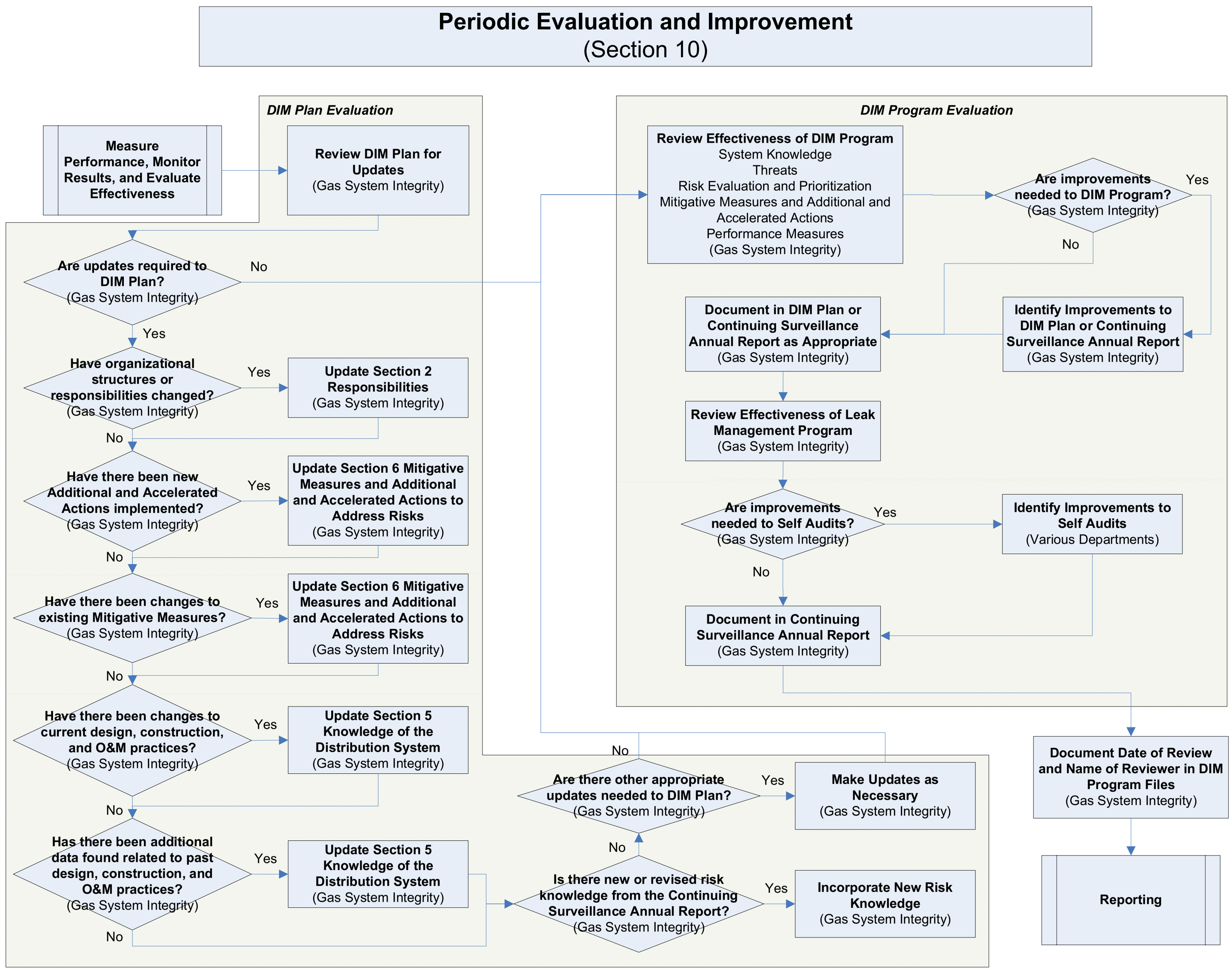


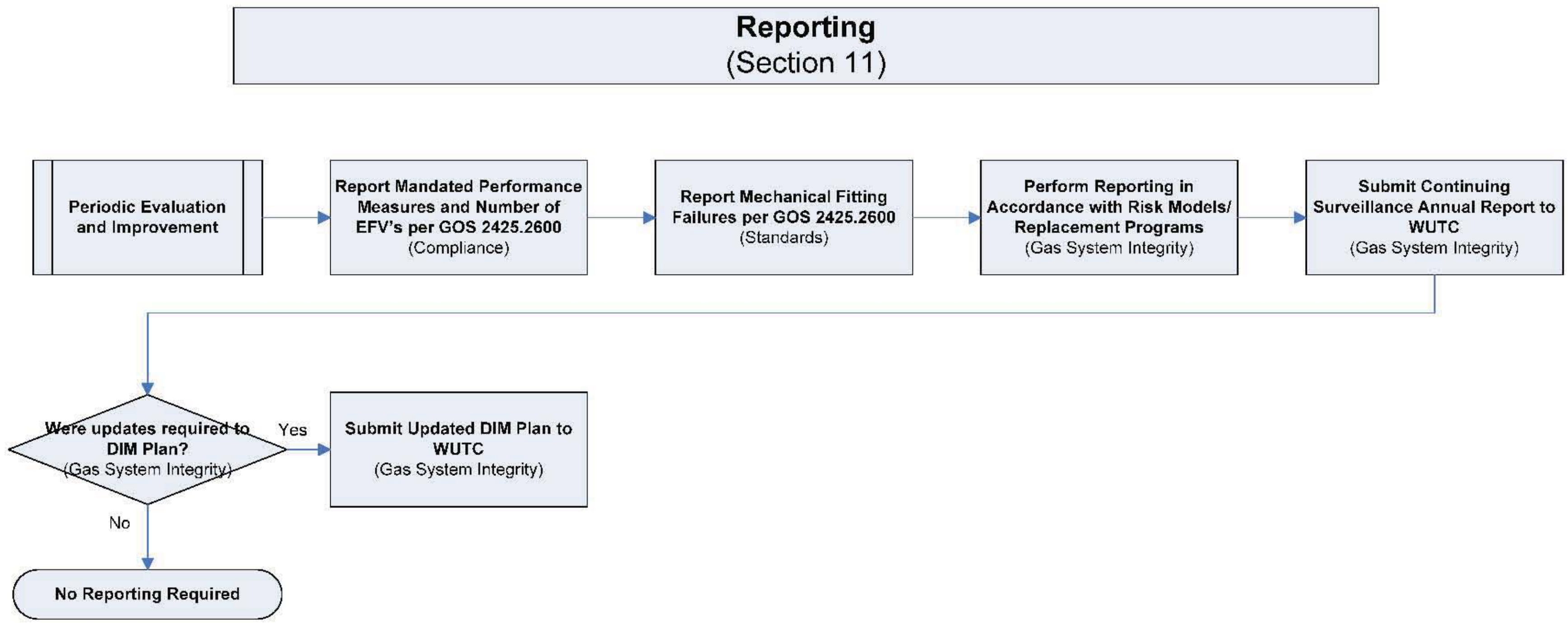

Threat Identification and Assessment
(Section 6)
Knowledge of the Distribution System
Assess and Identify Existing Primary Threats (Gas System Integrity)
Assess and Identify Existing Sub-Threats (Gas System Integrity)
Assess and Identify Potential Threats (Gas System Integrity)
Are any new threats, sub-threats, and/or potential threats identified? (Gas System Integrity)
Yes
No
Document Identified Threats in Continuing Surveillance Annual Report (Gas System Integrity)
Risk Evaluation and Prioritization
System Knowledge
Incident and Leak History
Corrosion Control History
Continuing Surveillance Records
Patrolling Records
Maintenance History
Excavation Damage Experience


Risk Evaluation and Prioritization
(Section 7)
Threat Identification and Assessment
Review Each Applicable Current and Potential Threat (Gas System Integrity)
Determine Consequence of Failure (Gas System Integrity)
Determine Likelihood of Failure (Gas System Integrity)
Evaluate the Relevance of Threats in One Location to Other Areas (Gas System Integrity)
Evaluate the Impact to the Total Risk When a Combination of Threats Exists on a Pipeline Segment (Gas System Integrity)
Risk Evaluation and Prioritization Matrix (Gas System Integrity)
Determine Relative Risk Score (Gas System Integrity)
Determine Risk Prioritization (Gas System Integrity)
Validate Risk Evaluation and Prioritization (Gas System Integrity)
Risk Evaluation and Prioritization Process
System Knowledge
Incident and Leak History
Corrosion Control History
Continuing Surveillance Records
Patrolling Records
Maintenance History
Excavation Damage Experience
Are risk ranking results valid? (Gas System Integrity)
Yes
No
Review Risk Evaluation and Prioritization Process (Gas System Integrity)
Does risk evaluation and prioritization process need to be revised? (Gas System Integrity)
Yes
No
Document Justification for Not Revising Process in Continuing Surveillance Annual Report (Gas System Integrity)
Mitigative Measures and Additional Accelerated Actions to Address Risks


Mitigative Measures and Additional and Accelerated Actions to Address Risks
(Section 8)
Risk Evaluation and Prioritization
Do risks meet criteria for Additional and Accelerated Actions? (Gas System Integrity)
No
Document in Continuing Surveillance Annual Report (Gas System Integrity)
Yes
Are existing Additional and Accelerated Actions adequately addressing risks? (Gas System Integrity)
No
Identify New/Revised Additional and Accelerated Actions (Various Departments)
Yes
Are these Additional and Accelerated Actions already in place and currently implemented into the GOS, GFP or other applicable document? (Gas System Integrity)
Yes
Document Additional and Accelerated Actions in DIM Plan (Gas System Integrity)
No
Document Additional and Accelerated Actions in Continuing Surveillance Report (Gas System Integrity)
Evaluate New/Revised Additional and Accelerated Actions (Various Departments)
Are these Additional and Accelerated Actions feasible? (Various Departments)
Yes
Develop and Implement Additional and Accelerated Actions (Various Departments)
No
Revise Proposed Additional and Accelerated Actions (Various Departments)
Yes
Should Additional and Accelerated Actions be revised? (Various Departments)
Are these Additional and Accelerated Actions implemented? (Various Departments)
Yes
No
No
Identify New Additional and Accelerated Action (Various Departments)
Yes
Should different Additional and Accelerated be evaluated? (Various Departments)
No
Document Justification and Conclusion in Continuing Surveillance Annual Report (Gas System Integrity)
Measure Performance, Monitor Results, and Evaluate Effectiveness


Measure Performance, Monitor Results, and Evaluate Effectiveness
(Section 9)
Mitigative Measures and Additional and Accelerated Actions to Address Risks
Identify Performance Measures (Various Departments)
Establish Baselines for Each Performance Measure (Various Departments)
Evaluate Performance Measure Results (Various Departments)
Validate Data Used to Trend Performance Measures (Gas System Integrity)
Does data accuracy need to be improved? (Gas System Integrity)
Yes
Document in Continuing Surveillance Annual Report (Gas System Integrity)
Compare Results to Established Baselines (Gas System Integrity)
Historical Data Accuracy
Subject Matter Expert Input
Evaluate Effectiveness of Additional and Accelerated Actions (Gas System Integrity)
Do Performance Measures need to be revised? (Gas System Integrity)
Yes
Document in Continuing Surveillance Annual Report (Gas System Integrity)
No
Are additional Performance Measures needed? (Gas System Integrity)
Yes
Document in Continuing Surveillance Annual Report (Gas System Integrity)
No
Are Additional and Accelerated Actions effective? (Gas System Integrity)
No
Document in Continuing Surveillance Annual Report (Gas System Integrity)
Yes
Review Results from Self Audit on Leak Management Program (Gas System Integrity)
Is Self Audit effective? (Gas System Integrity)
Yes
No
Document in Continuing Surveillance Annual Report (Gas System Integrity)
Periodic Evaluation and Improvement


Periodic Evaluation and Improvement
(Section 10)
DIM Plan Evaluation
Measure Performance, Monitor Results, and Evaluate Effectiveness
Review DIM Plan for Updates (Gas System Integrity)
Are updates required to DIM Plan? (Gas System Integrity)
No
Yes
Have organizational structures or responsibilities changed? (Gas System Integrity)
Yes
Update Section 2 Responsibilities (Gas System Integrity)
No
Have there been new Additional and Accelerated Actions implemented? (Gas System Integrity)
Yes
Update Section 6 Mitigative Measures and Additional and Accelerated Actions to Address Risks (Gas System Integrity)
No
Have there been changes to existing Mitigative Measures? (Gas System Integrity)
Yes
Update Section 6 Mitigative Measures and Additional and Accelerated Actions to Address Risks (Gas System Integrity)
No
Have there been changes to current design, construction, and O&M practices? (Gas System Integrity)
Yes
Update Section 5 Knowledge of the Distribution System (Gas System Integrity)
No
Has there been additional data found related to past design, construction, and O&M practices? (Gas System Integrity)
Yes
Update Section 5 Knowledge of the Distribution System (Gas System Integrity)
No
Is there new or revised risk knowledge from the Continuing Surveillance Annual Report? (Gas System Integrity)
Yes
Incorporate New Risk Knowledge (Gas System Integrity)
No
Are there other appropriate updates needed to DIM Plan? (Gas System Integrity)
Yes
Make Updates as Necessary (Gas System Integrity)
No
DIM Program Evaluation
Review Effectiveness of DIM Program
System Knowledge
Threats
Risk Evaluation and Prioritization
Mitigative Measures and Additional and Accelerated Actions
Performance Measures
(Gas System Integrity)
Are improvements needed to DIM Program? (Gas System Integrity)
Yes
No
Identify Improvements to DIM Plan or Continuing Surveillance Annual Report (Gas System Integrity)
Document in DIM Plan or Continuing Surveillance Annual Report as Appropriate (Gas System Integrity)
Review Effectiveness of Leak Management Program (Gas System Integrity)
Are improvements needed to Self Audits? (Gas System Integrity)
Yes
Identify Improvements to Self Audits (Various Departments)
No
Document in Continuing Surveillance Annual Report (Gas System Integrity)
Document Date of Review and Name of Reviewer in DIM Program Files (Gas System Integrity)
Reporting


Reporting
(Section 11)
Periodic Evaluation and Improvement
Report Mandated Performance Measures and Number of EFV's per GOS 2425.2600
(Compliance)
Report Mechanical Fitting Failures per GOS 2425.2600
(Standards)
Perform Reporting in Accordance with Risk Models/ Replacement Programs
(Gas System Integrity)
Submit Continuing Surveillance Annual Report to WUTC
(Gas System Integrity)
Were updates required to DIM Plan?
(Gas System Integrity)
Yes
Submit Updated DIM Plan to WUTC
(Gas System Integrity)
No
No Reporting Required

Appendix B: Knowledge of the Distribution System

The following appendices contained within Appendix B are documents of specific elements of System Knowledge that are documented and/or were researched to increase risk knowledge.

Appendix B-1: Summary of System Knowledge

This section summarizes the different sources of information that composes System Knowledge. This information is available in many forms and includes historical and current design, construction, and operation and maintenance practices. Table B-1 describes the different formats this information is available in and Table B-2 summarizes the records pertaining to the system and Table B-3 summarizes the general and industry system knowledge.

Table B-1. Document Types and Descriptions

Document Type	Description
Paper (Electronic)	Paper format, hard copy, but available electronically (PDF, .tiff, etc.)
Electronic	Electronic format (MS Excel spreadsheet, MS Word document, etc.)
Database	Database (Access, SQL Server, SAP WMS, etc.)

Table B-2. Summary of Records

Records	Document Type	Location of Document/Database	Key Department Contact
Operations and Plat Maps	Paper (Electronic)	Maps and Records and PSE Network Server	Maps and Records
Service Records (D4s)	Paper (Electronic)	Maps and Records and PSE Network Server	Maps and Records
As-Built Construction Drawings and Records	Paper (Electronic)	Maps and Records and PSE Network Server	Maps and Records
Gas Leak Management System	Database	PSE Network Server	System Control and Protection (Maintenance Programs)
Gas Leak Repair Records	Paper and Database	PSE Network Server	System Control and Protection (Maintenance Programs)
Cathodic Protection Maintenance Records (Rectifier Inspections and Test Site Inspections)	Database	SAP Work Management System	System Control and Protection (Corrosion Control)
Atmospheric Corrosion Inspection Records	Database	SAP Work Management System	Various Departments
Patrol Records	Database	SAP Work Management System / PSE Network Server	System Control and Protection (Maintenance Programs)
Valve Maintenance Records	Database	SAP Work Management System	Various Departments
Regulator Station Maintenance Records	Database	SAP Work Management System	System Control and Protection (Pressure Control)
Requests to Locate Gas Facilities	Electronic	One-Call Center	Contractor Management
Third-party damage Claims	Database	SAP Work Management System	Risk and Claims

Records	Document Type	Location of Document/Database	Key Department Contact
Main and Service Condition Reports	Database	SAP Work Management System	Various Departments
Liquid Removal Records	Paper	Environmental Services	Environmental Services
Material Failure Analysis Reports	Database	PSE Network Server	Standards
Mechanical Fitting Failure Reports	Paper	Standards	Standards
Material Failure and Construction Defect Reports	Paper (Electronic)	PSE Network Server	Compliance
PHMSA DOT Annual Reports	Paper (Electronic)	PSE Network Server	Compliance
PHMSA DOT Incident Reports	Paper (Electronic)	PSE Network Server	Compliance
WUTC Incident Reports	Paper (Electronic)	PSE Network Server	Compliance
Current Gas Operating Standards and Field Procedures	Electronic	PSE Network Server	Standards
Historical Gas Operating Standards and Field Procedures	Paper	Standards Library	Standards
Current Purchase Specifications	Database	SAP Work Management System	Purchasing/Standards
Historic Purchase Specifications	Paper	Standards Library	Standards

Table B-3. Summary of General and Industry System Knowledge

System Knowledge	Document Type	Location of Document/Database	Key Department Contact
General System Knowledge			
Subject Matter Expert Discussions	Electronic	DIM Program Files	Gas System Integrity
Performance Measure Data	Electronic	Continuing Surveillance Annual Report	Gas System Integrity
Backfill Practices	Electronic	DIM Plan Appendix	Gas System Integrity
Fusion Practices	Electronic	DIM Plan Appendix	Gas System Integrity
Installing Anode on Tracer Wire	Electronic	DIM Plan Appendix	Gas System Integrity
Steel Pipe Specifications	Electronic	DIM Plan Appendix	Gas System Integrity
Polyethylene Materials History	Electronic	DIM Plan Appendix	Gas System Integrity
Coating Types on Wrapped Steel Pipe (Services)	Electronic	DIM Plan Appendix	Gas System Integrity
Mechanical Fittings	Electronic	DIM Plan Appendix	Gas System Integrity
Celcon Caps	Electronic	DIM Plan Appendix	Gas System Integrity
Delrin Service Tap Tees	Electronic	DIM Plan Appendix	Gas System Integrity
Gas Quality	Paper (Electronic)	DIM Plan Appendix	Gas System Integrity
Bolt-on Tees	Electronic	DIM Plan Appendix	Gas System Integrity
Leak Cause Code I – Non-Exposed	Paper (Electronic)	DIM Plan Appendix	Gas System Integrity
Leak Cause Code Clarification	Paper (Electronic)	DIM Plan Appendix	Gas System Integrity
Industry Knowledge			
PPDC Manufacturers List	Electronic	DIM Program Files	Gas System Integrity
Advisory Bulletins	Paper (Electronic)	DIM Program Files	Gas System Integrity
Older PE Pipe	Paper (Electronic)	DIM Program Files	Gas System Integrity
Mechanical Fittings	Paper (Electronic)	DIM Program Files	Gas System Integrity
PE Pipe Timeline	Paper (Electronic)	DIM Program Files	Gas System Integrity

Appendix B-2: Steel Pipe Specifications

Historic Pipe Specifications and Design Pressures (CKOO 12302008)

	Pipe Properties					Design Pressures			Purchased Pipes Per Purchase Specifications															Stores Catalog			[redacted]					
Pipe Size (inches)	Pip O.D. (inches)	Wall Thickness (inches)	Pipe Grade	Yield Strength	Longitude Joint Factor (E)	Design Factor (F) of 0.2	Design Factor (F) of 0.4	Design Factor (F) of 1.0	4/9/1956	9/7/1966 (MISSING)	2/1/1968	5/9/1969 (MISSING)	8/20/1971	5/1/1972	12/22/1986	1/15/1988	3/25/1988	12/1/1988	12/15/1989 (MISSING)	3/5/1990	6/4/1990	9/2/1994	......	Feb-98	Aug-98	......	2002	2003	2004	2005	2006	2007
	0.840	0.109	Gr.A25	25000	0.600	779	1557	3893			√		√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
1/2	0.840	0.109	Gr.A	30000	1.000	1557	3114	7786														√(2)	......	B &W	B &W	......						
	0.840	0.109	Gr.B	35000	1.000	1817	3633	9083														√(2)	......	B &W	B &W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	1.050	0.113	Gr. A25	25000	0.600	646	1291	3229	√(1)		√		√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
3/4	1.050	0.113	Gr.A	30000	1.000	1291	2583	6457														√(2)	......	B &W	B &W	......						
	1.050	0.113	Gr.B	35000	1.000	1507	3013	7533														√(2)	......	B &W	B &W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	1.315	0.133	Gr. A25	25000	0.600	607	1214	3034	√(1)		√		√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
1	1.315	0.133	Gr.A	30000	1.000	1214	2427	6068														√(2)	......	B &W	B &W	......						
	1.315	0.133	Gr.B	35000	1.000	1416	2832	7080														√(2)	......	B &W	B &W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	1.660	0.140	Gr. A25	25000	0.600	506	1012	2530	√(1)		√		√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
1-1/4	1.660	0.140	Gr.A	30000	1.000	1012	2024	5060														√(2)	......	B &W	B &W	......						
	1.660	0.140	Gr.B	35000	1.000	1181	2361	5904														√(2)	......	B &W	B &W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	1.900	0.145	Gr. A25	25000	0.600	458	916	2289	√(1)		√				√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
1-1/2	1.900	0.145	Gr.A	30000	1.000	916	1832	4579														√(2)	......	B	B	......						
	1.900	0.145	Gr.B	35000	1.000	1068	2137	5342														√(2)	......	B	B	......	B	B	B	B	B	B
	2.375	0.125	Gr.A25	25000	0.600	316	632	1579						√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
	2.375	0.125	Gr.A	30000	1.000	632	1263	3158														√(2)	......			......						
	2.375	0.125	Gr.B	35000	1.000	737	1474	3684														√(2)	......			......						
2	2.375	0.154	Gr. A25	25000	0.600	389	778	1945	√(1)		√		√(2)	√(2)	√(2)	√(2)	√(3)	√(2)		√(2)	√(2)		......			......						
	2.375	0.154	Gr.A	30000	1.000	778	1556	3891														√(2)	......	B &W	B &W	......						
	2.375	0.154	Gr.B	35000	1.000	908	1816	4539														√(2)	......	B &W	B &W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	3.500	0.216	Gr. A25	25000	0.600	370	741	1851	√(1)				√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)		......			......						
3	3.500	0.216	Gr.A	30000	1.000	741	1481	3703														√(2)	......	?	?	......						
	3.500	0.216	Gr.B	35000	1.000	864	1728	4320														√(2)	......	?	?	......	B	B	B	B	B	B
	4.500	0.141	Gr. B	35000	1.000	439	877	2193					√(2)	√(2)	√(2)	√(2)	√(2)						......			......						
	4.500	0.141	X42	42000	1.000	526	1053	2632										√(2)		√(2)	√(2)	√(2)	......			......						
	4.500	0.188	Gr. B	35000	1.000	585	1170	2924			√		√(2)	√(2)	√(2)	√(2)	√(2)						......			......						
4	4.500	0.188	X42	42000	1.000	702	1404	3509										√(2)		√(2)	√(2)	√(2)	......	B & W	B & W	......	B & XT	B & XT	B & XT	B & XT	B & XT	B & XT
	4.500	0.237	Gr. A25	25000	0.600	316	632	1580	√(1)														......			......						
	4.500	0.237	Gr. B	35000	1.000	737	1475	3687	√(2)														......			......						
	4.500	0.237	X42	42000	1.000	885	1770	4424															......			......			B	B	B & FB	B & FB
	6.625	0.188	Gr. B	35000	1.000	397	795	1986			√		√(2)	√(2)	√(2)	√(2)	√(2)						......			......						
	6.625	0.188	X42	42000	1.000	477	953	2384										√(2)		√(2)	√(2)	√(2)	......	B & W	B & W	......	B & XT	B & FB	B & FB	B & FB	B & FB	B & FB
6	6.625	0.250	Gr.B	35000	1.000	528	1057	2642	√(2)														......	B	B	......	B					

	6.625	0.280	Gr.B	35000	1.000	592	1183	2958															......			......		B	B	B	B	B
	6.625	0.280	X42	42000	1.000	710	1420	3550															......			......		FB	FB	FB	FB	FB
8	8.625	0.188	Gr. B	35000	1.000	305	610	1526	√(2)		√		√(2)	√(2)	√(2)	√(2)	√(2)						......			......						
	8.625	0.188	X42	42000	1.000	366	732	1831										√(2)		√(2)	√(2)	√(2)	......	B & W	B & W	......	B & XT	B & FB	B & FB	B & FB	B & FB	B & FB
	8.625	0.188	X52	52000	1.000	453	907	2267															......	W*	W*	......						
	8.625	0.250	Gr. B	35000	1.000	406	812	2029													√(2)	√(2)	......	B	B	......	B	B	B	B	B	B
	8.625	0.322	X42	42000	1.000	627	1254	3136															......	W	W	......	XT	FB	FB	B & FB	B & FB	B & FB
10	10.750	0.219	Gr. B	35000	1.000	285	570	1426	√(2)														......			......						
12	12.750	0.219	Gr. B	35000	1.000	240	481	1202			√												......			......						
	12.750	0.219	X42	42000	·1.000	289	577	1443															......	B	B	......	B	B	B	B	B	B
	12.750	0.219	X46	46000	1.000	316	632	1580					√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)	√(2)	......	W	W	......	XT	FB	FB	FB	FB	FB
	12.750	0.250	Gr. B	35000	1.000	275	549	1373	√(2)														......	B	B	......	B	B	B	B	B	B
	12.750	0.250	X42	42000	1.000	329	659	1647							√(2)	√(2)	√(2)	√(2)		√(2)	√(2)	√(2)	......	B, CT, XT	B, CT, XT	......	B	B	B	B	B	B
	12.750	0.312	X42	42000	1.000	411	822	2056													√(2)	√(2)	......			......						
	12.750	0.312	X52	52000	1.000	509	1018	2545															......	W & XT	W & XT	......	XT	FB	FB	FB	FB	FB
16	16.000	0.219	X42	42000	1.000	230	460	1150			√												......			......						
	16.000	0.250	X42	42000	1.000	263	525	1313	√(2)														......	W*	W*	......						
	16.000	0.281	X46	46000	1.000	323	646	1616					√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)	√(2)	......			......						
	16.000	0.344	X56	56000	1.000	482	963	2408															......	W	W	......						
	16.000	0.375	X56	56000	1.000	525	1050	2625															......	XT	XT	......	XT	FB	FB	FB	FB	FB
	16.000	0.375	X60	60000	1.000	563	1125	2813															......			......	FB	FB	FB	FB	FB	FB
20	20.000	0.312	X42	42000	1.000	262	524	1310	√(2)		√												......			......						
	20.000	0.312	X52	52000	1.000	324	649	1622					√(2)	√(2)	√(2)	√(2)	√(2)	√(2)		√(2)	√(2)	√(2)	......			......						
	20.000	0.375	X56	56000	1.000	420	840	2100															......	CT*	CT*	......						
	20.000	0.500	?	?	1.000	########	#VALUE!	########															......	XT*	XT*	......						

Notes:

Footnote (1) - Pipe to be used in the distribtuion system and the supply main system designed for operation pressures not to exceed 200 psig

Footnote (2) - Pipe to be used in supply main system designed for operation pressure not to exceed 300 psig

The above table does not apply to the original construction of the Vashon Island and Gig Harbor crossing which pipes were ordered under special specification (8-5/8" OD, 0.322 wall, Grade X-46)

Design pressures were calculated using the steel pipe formula provided by Part 49 CFR 192.105 -> P=(2St)/DxFxExT, where E = 0.6 for furnace butt welded pipe, E = 1 for non-furnace but welded pipe, T = 1

Footnote (*) implies that those material were listed as "phased out items" on the store catalog

Entries "B" = bare pipe, "W" = wrapped pipe, "XT" = X Thru coated pipe, "CT" coal tar pipe, "FB" = FBE coated pipe.

Historic Pipe Specifications SMYS Calculations

DATE	Pipe Size (inches)	Pipe Grade	Wall Thickness (inches)	Material Type	150 psig MAOP	190 psig MAOP	250 psig MAOP	280 psig MAOP	Yield Strength	Pressure (psig)	Pressure (psig)	Pressure (psig)	Pressure (psig)	Pipe O.D. (inches)
Specifications for pipe (dated 4/9/56)	4	Gr. B	0.237	STW	4.1	5.2	6.8	7.6	35000	150	190	250	280	4.5
	6	Gr. B	0.250	STW	5.7	7.2	9.5	10.6	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625
	10	Gr. B	0.219	STW	10.5	13.3	17.5	19.6	35000	150	190	250	280	10.75
	12	Gr. B	0.250	STW	10.9	13.8	18.2	20.4	35000	150	190	250	280	12.75
	16	X42	0.250	STW	11.4	14.5	19	21.3	42000	150	190	250	280	16
	20	X42	0.312	STW	11.4	14.5	19.1	21.4	42000	150	190	250	280	20
(missing specification dated 9/7/66)														
Specifications for pipe (dated 2/1/68)	4	Gr. B	0.188	STW	5.1	6.5	8.5	9.6	35000	150	190	250	280	4.5
	6	Gr. B	0.188	STW	7.6	9.6	12.6	14.1	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625
	12	Gr. B	0.219	STW	12.5	15.8	20.8	23.3	35000	150	190	250	280	12.75
	16	X42	0.219	STW	13	16.5	21.7	24.4	42000	150	190	250	280	16
	20	X42	0.312	STW	11.4	14.5	19.1	21.4	42000	150	190	250	280	20
(missing specification dated 5/9/69)														
Specifications for pipe (dated 8/20/71)	4	Gr. B	0.141	STW	6.8	8.7	11.4	12.8	35000	150	190	250	280	4.5
	4	Gr. B	0.188	STW	5.1	6.5	8.5	9.6	35000	150	190	250	280	4.5
	6	Gr. B	0.188	STW	7.6	9.6	12.6	14.1	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
Specifications for pipe (dated 5/1/72)	4	Gr. B	0.141	STW	6.8	8.7	11.4	12.8	35000	150	190	250	280	4.5
	4	Gr. B	0.188	STW	5.1	6.5	8.5	9.6	35000	150	190	250	280	4.5
	6	Gr. B	0.188	STW	7.6	9.6	12.6	14.1	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
Specifications for pipe (dated 12/22/86)	4	Gr. B	0.141	STW	6.8	8.7	11.4	12.8	35000	150	190	250	280	4.5
	4	Gr. B	0.188	STW	5.1	6.5	8.5	9.6	35000	150	190	250	280	4.5
	6	Gr. B	0.188	STW	7.6	9.6	12.6	14.1	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	12	X42	0.250	STW	9.1	11.5	15.2	17	42000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
Specifications for pipe (dated 1/15/88)	4	Gr. B	0.141	STW	6.8	8.7	11.4	12.8	35000	150	190	250	280	4.5
	4	Gr. B	0.188	STW	5.1	6.5	8.5	9.6	35000	150	190	250	280	4.5
	6	Gr. B	0.188	STW	7.6	9.6	12.6	14.1	35000	150	190	250	280	6.625
	8	Gr. B	0.188	STW	9.8	12.5	16.4	18.4	35000	150	190	250	280	8.625

DATE	Pipe Size (inches)	Pipe Grade	Wall Thickness (inches)	Material Type	150 psig MAOP	190 psig MAOP	250 psig MAOP	280 psig MAOP	Yield Strength	Pressure (psig)	Pressure (psig)	Pressure (psig)	Pressure (psig)	Pipe O.D. (inches)
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	12	X42	0.250	STW	9.1	11.5	15.2	17	42000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
Specifications for pipe (dated 12/1/88)	4	X42	0.141	STW	5.7	7.2	9.5	10.6	42000	150	190	250	280	4.5
	4	X42	0.188	STW	4.3	5.4	7.1	8	42000	150	190	250	280	4.5
	6	X42	0.188	STW	6.3	8	10.5	11.7	42000	150	190	250	280	6.625
	8	X42	0.188	STW	8.2	10.4	13.7	15.3	42000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	12	X42	0.250	STW	9.1	11.5	15.2	17	42000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
(missing specification dated 12/15/89)														
Specifications for pipe (dated 3/5/90)	4	X42	0.141	STW	5.7	7.2	9.5	10.6	42000	150	190	250	280	4.5
	4	X42	0.188	STW	4.3	5.4	7.1	8	42000	150	190	250	280	4.5
	6	X42	0.188	STW	6.3	8	10.5	11.7	42000	150	190	250	280	6.625
	8	X42	0.188	STW	8.2	10.4	13.7	15.3	42000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	12	X42	0.250	STW	9.1	11.5	15.2	17	42000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20
Specifications for pipe (dated 6/4/90)	4	X42	0.188	STW	4.3	5.4	7.1	8	42000	150	190	250	280	4.5
	4	X42	0.237	STW	3.4	4.3	5.7	6.3	42000	150	190	250	280	4.5
	6	X42	0.188	STW	6.3	8	10.5	11.7	42000	150	190	250	280	6.625
	8	X42	0.188	STW	8.2	10.4	13.7	15.3	42000	150	190	250	280	8.625
	8	Gr. B	0.250	STW	7.4	9.4	12.3	13.8	35000	150	190	250	280	8.625
	12	X46	0.219	STW	9.5	12	15.8	17.7	46000	150	190	250	280	12.75
	12	X42	0.250	STW	9.1	11.5	15.2	17	42000	150	190	250	280	12.75
	12	X42	0.312	STW	7.3	9.2	12.2	13.6	42000	150	190	250	280	12.75
	16	X46	0.281	STW	9.3	11.8	15.5	17.3	46000	150	190	250	280	16
	20	X52	0.312	STW	9.2	11.7	15.4	17.3	52000	150	190	250	280	20

*%SMYS is calculated by solving for F in the design formula for steel pipe P=(2St)/DxFxExT (CFR 192.105) where P = 150 psig or 190 psig or 250 psig or 280 psig; S = yield strength (pipe grade); t = wall thickness; D = nominal OD; E = 1 and T = 1.

Appendix B-3: Polyethylene Pipe Material Information

The following table is a summary of the polyethylene pipe material information that has been installed in the gas distribution system. This includes the approximate installation period, pipe manufacturer, brand name of pipe, and material designation. This summary is based on Subject Matter Expert, purchase specifications, fusion qualification documents, Gas Operating Standards, Gas Field Procedures, and previous research completed by the Standards department. For complete version and reference documentation, see DIM Program files.

Table 1: Summary of Polyethylene Pipe Material

Installation Period	Manufacturer	Brand Name	Material Designation
Early 1970s - 1977[1]	Phillips	Driscopipe M7000[2]	HDPE 3306/3406[3]
1977 - 1985	Dupont	Aldyl HD	HDPE 3406
Early 1980s - 1984	Phillips	Driscopipe M7000	HDPE 3406
1984[1] - 1988[2]	Phillips	Driscopipe M8000	HDPE 3408
1988 - 2011	Plexco (Performance Pipe)	Yellowstripe	HDPE 3408
1995 - 2008	Plexco (Performance Pipe)	Yellowpipe	MDPE 2406
2008 - 2011	Performance Pipe	Driscoplex 6500	MDPE 2406/2708

Appendix B-4: Backfill Practices

The following document was researched and compiled by the Standards Department. For the referenced documents, see DIM Program files.

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2009-2011	Steel w/rock shield wrap or encased PE or encased Steel	Main and or Service	not required	not required	The Steel pipe has an approved rock shield wrap or the Steal or PE pipe is encased or the pipe is installed with plowing	Final backfill shall be soil-based select material, native soil, or an approved special backfill. Well graded or poorly graded gravel with a max of 5% fines. Shall not contain rocks larger then 10 inches in diameter except if steel pipe is larger then 8 in then rocks may be the lesser of 12 inches in diameter or 100 lbs. Shall not contain rocks larger then 6 inches diameter when steel carrier pipe is wrapped in approved rock shield material.	Can only use Controlled Density Fill if 6 inches cover of initial backfill is used. When Municipality requirements for control density fill conflict with PSE Specification 1275.1475, the municipality requirements should be followed. (Unknown possible material)	Yes (95% standard Proctor for paved areas or roadways and 85% for non traffic areas.) For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe with final backfill material cover pipe with final backfill material. Compact.	Final back fill depth found in 2525.1700. All information taken from 2011 GOS and looked through previous working papers until standard changes affected Acquisition data. See Backfill DIMP Document Binder for printed out Affecting Documents	2011 through 2009 working papers GOS 2525.1800 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2011 and 2011 customer trench and backfill	PE or Steel	Main and or Service	Sand meeting PSE Specification 1275.1380. Can use sandbags to support the pipe in conjunction with sand backfill. When backfilling subsequent to maintenance or repair of an existing pipeline, including service riser replacements, and when the location being backfilled is not under a hard surface that is subject to vehicular traffic, initial backfill may be native material that is well-graded or poorly graded native soil that does not contain fines; angular or sub angular rocks; or rounded or sub rounded rocks larger than 1/2-inch diameter.	Put 4 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. When backfilling subsequent to maintenance or repair of an existing pipeline, including service riser replacements, and when the location being backfilled is not under a hard surface that is subject to vehicular traffic, initial backfill may be native material that is well-graded or poorly graded native soil that does not contain fines; angular or sub angular rocks; or rounded or sub rounded rocks larger than 1/2-inch diameter. There must be 6 in of initial backfill covering the pipe line after compaction. Initial backfill shall be used for the first 12 inches of cover, after compaction, if the final backfill contains rocks larger than 8 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil, or an approved special backfill. Well graded or poorly graded gravel with a max of 5% fines. Shall not contain rocks larger then 10 inches in diameter except if steel pipe is larger then 8 in then rocks may be the lesser of 12 inches in diameter or 100 lbs. Shall not contain rocks larger then 6 inches diameter when steel carrier pipe is wrapped in approved rock shield material.	Controlled Density Fill. When Municipality requirements for control density fill conflict with PSE Specification 1275.1475, the municipality requirements should be followed. (Unknown possible material)	Yes (95% standard Proctor for paved areas or roadways and 85% for non traffic areas.) For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2011 GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2010 and 2010 customer trench and backfill	PE or Steel	Main and or Service	Sand meeting PSE Specification 1275.1380. Can use sandbags to support the pipe in conjunction with sand backfill.	Put 4 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. When backfilling subsequent to maintenance or repair of an existing pipeline, including service riser replacements, and when the location being backfilled is not under a hard surface that is subject to vehicular traffic, initial backfill may be native material that is well-graded or poorly graded native soil that does not contain fines; angular or sub angular rocks; or rounded or sub rounded rocks larger than 1/2-inch diameter. There must be 6 in of initial backfill covering the pipe line after compaction. Initial backfill shall be used for the first 12 inches of cover, after compaction, if the final backfill contains rocks larger than 8 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil, or an approved special backfill. Well graded or poorly graded gravel with a max of 5% fines. Shall not contain rocks larger then 10 inches in diameter except if steel pipe is larger then 8 in then rocks may be the lesser of 12 inches in diameter or 100 lbs. Shall not contain rocks larger then 6 inches diameter when steel carrier pipe is wrapped in approved rock shield material.	Controlled Density Fill.	Yes (95% standard Proctor for paved areas or roadways and 85% for non traffic areas.) For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2010 working papers GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2009 and 2009 customer trench and backfill	PE or Steel	Main and or Service	Sand meeting PSE Specification 1275.1380. Can use sandbags to support the pipe in conjunction with initial backfill. Initial backfill may be native material that is well-graded or poorly graded native soil that does not contain fines; angular or sub angular rocks; or rounded or sub rounded rocks larger than 1/2-inch diameter.	Put 4 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. When backfilling subsequent to maintenance or repair of an existing pipeline, including service riser replacements, and when the location being backfilled is not under a hard surface that is subject to vehicular traffic, initial backfill may be native material that is well-graded or poorly graded native soil that does not contain fines; angular or sub angular rocks; or rounded or sub rounded rocks larger than 1/2-inch diameter. There must be 6 in of initial backfill covering the pipe line after compaction. Initial backfill shall be used for the first 12 inches of cover, after compaction, if the final backfill contains rocks larger than 8 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil, or an approved special backfill. Well graded or poorly graded gravel with a max of 5% fines. Shall not contain rocks larger then 10 inches in diameter except if steel pipe is larger then 8 in then rocks may be the lesser of 12 inches in diameter or 100 lbs. Shall not contain rocks larger then 6 inches diameter when steel carrier pipe is wrapped in approved rock shield material.	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes (95% standard Proctor for paved areas or roadways and 85% for non traffic areas.) For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2009 working papers GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2008 and 2008 customer trench and backfill	PE or Steel	Main and or Service	Sand meeting PSE Specification, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter in accordance with 1275.1380. Rocks up to 1 inch in diameter may be used on fusion bonded epoxy-coated pipe 8 inches or greater in diameter. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Put 4 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the final backfill contains rocks larger than 8 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter except if steel pipe is larger then 8 inches and larger in diameter may have rocks up to the lesser of 12 inches in diameter or 100 pounds. Final backfill shall not contain rocks larger than 6 in diameter when the carrier pipe is wrapped in approved rock shield material to prevent damage to carrier pipe.	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2008 working papers GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2008	Steel w/rock shield wrap or encased PE or encased Steel	Main and or Service	not required	not required	The Steel pipe has an approved rock shield wrap or the Steal or PE pipe is encased or the pipe is installed with plowing	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter . Final backfill shall not contain rocks larger than 6 in diameter when the carrier pipe is wrapped in approved rock shield material to prevent damage to carrier pipe.	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2008 working papers GOS 2525.1800 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2007 to 2006 and 2007 to 2006 customer trench and backfill	PE or Steel	Main and or Service	Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter. Rocks up to 1 inch in diameter may be used on fusion bonded epoxy-coated pipe 8 inches or greater in diameter. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter. For cross country steel pipeline the final backfill can not contain rocks larger than 12-in. Diameter or rocks exceeding 100 lb	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2007 and 2006 working papers GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2007 to 2006	Steel w/rock shield wrap or encased PE or encased Steel	Main and or Service	Not required Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter. Rocks up to 1 inch in diameter may be used on fusion bonded epoxy-coated pipe 8 inches or greater in diameter. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Not Required. Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	The Steel pipe has an approved rock shield wrap or the Steal or PE pipe is encased or the pipe is installed with plowing	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 6 inches in diameter.	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2007 and 2006 working papers OS 2525.1800 and Safety Equipment, Tools, and Materials Catalog 1275.1475

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2005 to 2004 and 2005 to 2004 customer trench and backfill	PE or Steel	Main and or Service	Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter. Cross-Country steel Pipe must have Fusion Bonded Epoxy Coating and initial backfill must be able to pass through a one inch screen. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter. For cross country steel pipeline the final backfill can not contain rocks larger than 12-in. Diameter or rocks exceeding 100 lb	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2005 to 2004 working papers GOS 2525.1800, 2525.1600 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2005 to 2004	Steel w/rock shield wrap or encased PE or encased Steel	Main and or Service	Not required. Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter. Cross-Country steel Pipe must have Fusion Bonded Epoxy Coating and initial backfill must be able to pass through a one inch screen. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Not Required. Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	The Steel pipe has an approved rock shield wrap or the Steal or PE pipe is encased	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter.	Controlled Density Fill with a minimum of 6 inches cover of initial backfill over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2005 working papers OS 2525.1800 and Safety Equipment, Tools, and Materials Catalog 1275.1475

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
2003 to 2002 and 2003 to 2002 customer trench and backfill	PE or Steel	Main and or Service	Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch to 1 inch in diameter. Cross-Country steel Pipe must have Fusion Bonded Epoxy Coating and initial backfill must be able to pass through a one inch screen. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	N/A	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter. For cross country steel pipeline the final backfill can not contain rocks larger than 12-in. Diameter or rocks exceeding 100 lb	Controlled Density Fill or soil stabilization chemicals (used for soil compaction or stabilization) with a minimum of 6 inches cover of chemical free backfill material over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2002 to 2003 working papers OS 2525.1800 and 2525.1600 / 6.33 and Safety Equipment, Tools, and Materials Catalog 1275.1475
2003 to 2002	Steel w/rock shield wrap or encased PE or encased Steel	Main and or Service	Not required. Sand, native soil, or soil-based select material that does not contain sharp rocks or rocks larger than 1/2 inch in diameter. Cross-Country steel Pipe must have Fusion Bonded Epoxy Coating and initial backfill must be able to pass through a one inch screen. Can use sandbags or wood skids/wedges to support the pipe in conjunction with initial backfill. The Wood skids/wedges shall be removed before backfilling the trench.	Not Required. Put 3 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces. Initial backfill shall be used for at least the first 6 inches of cover. Initial backfill shall be used for the first 12 inches of cover if the native soil contains rocks larger than 6 inches in diameter.	The Steel pipe has an approved rock shield wrap or the Steal or PE pipe is encased	Final backfill shall be soil-based select material, native soil. Shall not contain rocks larger then 10 inches in diameter. For cross country steel pipeline the final backfill can not contain rocks larger than 12-in. Diameter or rocks exceeding 100 lb	Controlled Density Fill or soil stabilization chemicals (used for soil compaction or stabilization) with a minimum of 6 inches cover of chemical free backfill material over the pipe before the special mixture is installed.	Yes, For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	2002 to 2003 working papers OS 2525.1800 and Safety Equipment, Tools, and Materials Catalog 1275.1475
1996 Customer Trench and Backfill	PE or Steel	Main and or Service	Sand	Sand padding will be required over rocky areas (no specification of how much)	N/A	Final Backfill to Washington Natural Gas Company Standards. Must have trench inspected prior to backfilling	Not Specified	Not Specified	Support pipe, Install initial backfill, Customer installs a backfill material.	See Backfill DIMP Document Binder for printed out Affecting Documents	Found in 1996 Working papers for GOS 6.33 Washington Natural Gas Info.

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
1994 Customer Trench and Backfill	PE or Steel	Service	Sand or can have already buried conduit that the contractor could push or pull the pipe through.	Sand padding is required	N/A	not specified	Customers were allowed to install piping with in PVC Conduit.	Not Specified	Support pipe, Install initial backfill, Customer installs a backfill material.	See Backfill DIMP Document Binder for printed out Affecting Documents	Found in 1994 Working papers for GOS 6.33 Washington Natural Gas Info.
1991	Steel and Plastic	Main and service	It must be free of large objects and large clods	If trench bottom is uneven, at least 6 inches of rock free soil shall be used for bedding pipe.	N/A	not specified	not specified	Yes. Backfill shall be tamped at the sides of the pipe. For portable hand tamper/ compactors, compact after there is at least 12 in of lift height and 24 in of lift height if using a machine mounted compactor. Back fill lift should be in 6 inch layers after the initial lift. Water Jetting may be used.	Support pipe, Install initial backfill, and install final backfill material. Compact.	Water Jetting as a form of compacting does not seem like a very good method from what I read on the internet. See Backfill DIMP Document Binder for printed out Affecting Documents.	Fitter Training manual revised 1991 updated September 1992
1985	Does not Specify	"Distribution Main Specifications, construction"	Soft earth or sand	Put 6 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces.	Does not Specify	Does not Specify	Does not Specify	Does not Specify	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	Washington Natural Gas Company, Operation Standard 6.8 effective date 10-15-85
1978	Steel	Main and Service	Material free from rocks, hard clods, soft or unstable dirt, or other unstable materials.	Needs at least 6 inches of cover over pipe. Shall be thoroughly compacted before the final backfill is added.	N/A	Shall contain no rocks, broken concrete, or other materials larger than ordinary brick, nor any soft or unstable dirt.	N/A	Yes. Compactor machines are restricted to use over the pipe trench only and points of transition from plastic to steel shall be compacted by hand. Water Jetting was also allowed.	Support pipe, Install initial backfill, and install final backfill material. Compact.	Water Jetting as a form of compacting does not seem like a very good method from what I read on the internet. See Backfill DIMP Document Binder for printed out Affecting Documents	Washington Natural gas Co. Fitters Manual Revised March 1978.

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
1978	Plastic	Main and Service	Material free from rocks, hard clods, soft or unstable dirt, or other unstable materials.	Must provide firm continuous support under and around pipe. Material used for support must be well compacted. At least 6 inches of select rock free soil shall be used for bedding pipe if the trench bottom is not smooth.	N/A	Shall contain no rocks, broken concrete, or other materials larger than ordinary brick, nor any soft or unstable dirt.	N/A	Yes. Shall be tamped at the sides of plastic pipe, but shall not be tamped over the pipe until an 18 inch cover is attained. Compactor machines are restricted to use over the pipe trench only and points of transition from plastic to steel shall be compacted by hand. Water Jetting was also allowed.	Support pipe, Install initial backfill, and install final backfill material. Compact.	Water Jetting as a form of compacting does not seem like a very good method from what I read on the internet. See Backfill DIMP Document Binder for printed out Affecting Documents.	Washington Natural gas Co. Fitters Manual Revised March 1978.
1977	Does not Specify	"Distribution Main Specifications, Construction"	Material free from rocks, hard clods, soft or unstable dirt, or other unstable materials.	Needs at least 6 inches of cover over pipe. Shall be thoroughly compacted before the final backfill is added.	N/A	Shall contain no rocks, broken concrete, or other materials larger than ordinary brick, nor any soft or unstable dirt.	Special chemicals are used for soil stabilization, "only chemicals that have been approved by the engineering Department shall be used for soil conditioning.	Yes. Initial backfill shall be thoroughly compacted before final backfill is installed. The soil shall be compacted with air driven or mechanical tampers, except in well drained soil water settling is allowed.	Support pipe, Install initial backfill, compact, and install final backfill material. Compact.	Water settling may be the same as water jetting.	Washington Natural Gas Company, Operation Standard 6.13 effective date 7-20-77 replaced 12-22-66
1969	Does not Specify	"Distribution Main Specifications, construction"	Soft earth or sand	Put 2 in of initial backfill under pipe if trench bottom contains any sharp or unusually rough surfaces.	Does not Specify	Does not Specify	Does not Specify	Does not Specify	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	Washington Natural Gas Company, Operation Standard 6.8 effective date 2-28-69 replaced 2-28-69

Time Period	Pipe Material	Main/Service	Initial Backfill Type	How Much Initial Backfill Requirement	Initial Backfill Not Required	Final Backfill Type	Special Backfill Type	Requires Compaction	General Backfill Practice	Comments	Reference Document Title
1966	Does not Specify	"Distribution Main Specifications, construction"	Material free from rocks, hard clods, soft or unstable dirt, or other unstable materials.	Needs at least 6 inches of cover over pipe. Shall be thoroughly compacted before the final backfill is added.	N/A	Shall contain no rocks, broken concrete, or other materials larger than ordinary brick, nor any soft or unstable dirt.	N/A	Yes. Initial backfill shall be thoroughly compacted before final backfill is installed. The soil shall be compacted with air driven or mechanical tampers, except in well drained soil water settling is allowed.	Support pipe, Install initial backfill, compact, and install final backfill material. Compact.	Water settling may be the same as water jetting.	Washington Natural Gas Company, Operation Standard 6.13 effective date 12-22-66 replaced 12-22-66
1960	The Standard only references Steel	"Distribution Main Specification, Construction" This could possibly apply to Main and services b/c I did not find reference to service and the manual referred to mains of 2" or less for the welding portion.	Soft earth or sand, Material that is free from rocks, hard clods, soft or unstable dirt.	If installing pipe on sharp or rocky soil place 2 in of sand or soft earth to protect the pipe and then at least 6 in of cover.	N/A	Shall contain no rocks, broken concrete or other materials larger than ordinary brick, nor any soft or unstable dirt.	N/A	Soil shall be compacted with air driven or mechanical tampers.	Support pipe, Install initial backfill, and install final backfill material. Compact.	See Backfill DIMP Document Binder for printed out Affecting Documents	Washington Natural Gas company Standard Practices 2550.2 page 9. sec 5 issued 6-17-60

Appendix B-5: Fusion Practices

The following is an excerpt of the document that was researched and compiled by the Standards Department. The document summarizes current and past fusion practices. For the complete version of this document and referenced documents, see DIM Program files.

Time Period	Fusion Types	Fusion Machine	Pipe Material	Pipe Size	Fusion Pressure	Temperature Requirement	Validating Temperature	Pipe Preparation Specification	Final Joint Requirement	Fusing in Cold Weather	General Requirements	Comments	Reference Document
2011 to 2007	Butt Fusion (Manual Unit)	(all by McElroy) #2CU, #4CU, #2LC, #14, Mini-Mc, Use coated plates when performing all fusions.	MDPE, HDPE, Phillips HDPE requires more pressure to make a complete rollback.	1/2-inch CTS through 4-inch IPS PE pipe	Apply enough Pressure to produce a complete, uniform double rollback around the entire circumference of the fusion joint. Do not apply excessive force or the melt may push out and produce a cold fuse.	Allow heater to cycle 4-5 times before use. The adaptor plate temperature shall be 490° to 510° F. Take a reading on both sides of the adaptor plate in the fusion area.	Use a Calibrated Pyrometer or Infrared Gauge. Tool room personnel should check the temp weekly and fitters should check the temp each time the heater plates are plugged in and prior to fusing.	All butt fusions shall be at least three pipe diameters or 12 inches, whichever is greater, away from any new or existing squeeze point. Remove any section of pipe that has a cut gouge or scrape that is deeper than 10% of wall thickness, Align pipe, using facing tool square the pipe ends and remove a minimum of 1/16 inch from ends. Facing may be stopped at approximately 50% of completion and inspected. Remove any remaining small shavings with a paper towel. Bring the pipe ends together and verify even alignment. If uneven or mitered, realign and reface for proper alignment of ends.	If rollback is not complete the fuse must be cut out and redone, For 1/2-inch CTS to 1-inch CTS fuse Bead must be 1/16-inch, for 1-1/4-inch IPS to 2-inch IPS the fusion bead must be 1/16-inch to 1/8-inch, and for 3-inch IPS to 4-inch IPS the fusion bead must be 1/8-inch. Butt fusion alignment is visually inspected. If alignment is "High-Low" the joint must be cut out and refused. leak test	Shield the fusion process from wind, blowing snow and excessive heat loss from wind chill. Maintain specified heating tool surface temperature. Do not increase heating tool surface temp. Do not apply additional pressure during zero pressure heating steps. Do not increase fusion joining pressure. Time required to obtain proper melt may increase.	Procedure must be performed by individuals qualified under PSE's Operator Qualification Program and Operating Standard 2700.1600 (2009, 2008 and 2007 said Procedure must be performed by individuals qualified under PSE's Operator Qualification Program in the specific task or procedure. Individuals who are not qualified may perform this procedure only if they are continually and directly observed by a qualified person. as specified in Operating standard 2425.2100)	Cooling: once cool to touchable then wait 15 additional minutes. There are compensations for drag, see attached documents. Heat shields are required when fusing MDPE to HDPE for 1-1/4 inch through 4 inch IPS.	2011, 2010, 2009, 2008 and 2007 GFP 4600.1000, and 4600.1010

Time Period	Fusion Types	Fusion Machine	Pipe Material	Pipe Size	Fusion Pressure	Temperature Requirement	Validating Temperature	Pipe Preparation Specification	Final Joint Requirement	Fusing in Cold Weather	General Requirements	Comments	Reference Document
2011	Butt Fusion (Hydraulic Unit)	McElroy Rolling #28 Hydraulic Fusion Machine, TracStar #28 Hydraulic Fusion Machine, Connectra 28CQ or 28EP fusion machine.	IPS MDPE	6-inch and 8-inch diameter	For McElroy Rolling #28 Hydraulic Unit, TracStar #28 Hydraulic Unit, Connectra 28EP fusion machine with 6-inch MDPE gauge pressure should be 190± 15psig, with 8-inch MDPE gauge pressure should be 300± 15 psig. For Connectra 28CQ (Hand pump) fusion machine with 6-inch MDPE gauge pressure should be 415± 40psig, with 8-inch MDPE gauge pressure should be 680± 40 psig.	Allow heater to cycle 4-5 times before use. The adaptor plate temperature shall be 490° to 510° F. Take a reading on both sides of the adaptor plate in the fusion area.	Use a Calibrated Pyrometer or Infrared Gauge. Tool room personnel should check the temp weekly and fitters should check the temp each time the heater plates are plugged in and prior to fusing. Do not rely on the dial gauge on the heater plate	All butt fusions shall be at least three pipe diameters or 12 inches, whichever is greater, away from any new or existing squeeze point. Remove any section of pipe that has a cut gouge or scrape that is deeper than 10% of wall thickness, Clean the pipe inside and out, in the area the fusion will be. Place pipe/fitting/valve ends in machine and align the ends. Using facing tool square the pipe ends and remove a minimum of 1/16 inch from ends. Remove any remaining small shavings with a paper towel. Bring pipes together and verify alignment.	If rollback is not complete the fuse must be cut out and redone, watch for proper melt swell bead around entire circumference of both ends. Proper combined fusion bead dimensions for 6-inch IPS combined fusion bead width should be 1/4-inch to 3/8-inch, for 8-inch IPS the combined fusion bead width should be 3/8-inch to 1/2-inch. leak test	Shield the fusion process from wind, blowing snow and excessive heat loss from wind chill. Maintain specified heating tool surface temperature. Do not increase heating tool surface temp. DO not apply additional pressure for any procedure. Time required to obtain proper melt may increase.	Procedure must be performed by individuals qualified under PSE's Operator Qualification Program and Operating Standard 2700.1600	Cooling: once cool to touchable then wait 15 additional minutes. Heat shields are required when fusing MDPE to HDPE for 1-1/4-inch through 4-inch IPS. There are compensations for drag, see attached documents	2011 GFP 4600.1020

Time Period	Fusion Types	Fusion Machine	Pipe Material	Pipe Size	Fusion Pressure	Temperature Requirement	Validating Temperature	Pipe Preparation Specification	Final Joint Requirement	Fusing in Cold Weather	General Requirements	Comments	Reference Document
2011 to 2007	Joining Pipe by Side Fusion	McElroy #2 CU (Combination Unit) and the Sidewinder.	All Sidewall fusions shall be made with fittings that are the same density as the pipe. MDPE fittings on MDPE pipe and HDPE fittings on HDPE pipe.	There are no size restrictions	Use enough pressure to form a middle bead and hold the pressure constant. When using the side winder, approximately 150-200 psig on gauge for HDPE and 80-100 psig for MDPE.	Allow heater to cycle 4-5 times before use. The adaptor plate temperature shall be 490° to 510° F.	Use a Calibrated Pyrometer or Infrared Gauge. Tool room personnel should check the temp weekly and fitters should check the temp each time the heater plates are plugged in and prior to fusing. Take a reading on both sides of the plates.	All side wall fusions shall be at least three pipe diameters or 12 inches, whichever is greater, away from any new or existing squeeze point. Check the pipe/fitting/valve for cuts gouges, scrapes removing any section that has a cut gouge, or scrape deeper than 10% of the wall thickness. Clean the pipe inside and out in the area the fusion will be. Place pipe/fitting/valve ends in machine and align the ends. Roughen the area of the pipe to be fused with a medium grade utility cloth until the smooth coating is removed. No bolster or inserts are required for 8-inch IPS. Clean off the heater and the bottom of the adaptor plate. Recommended: use an uncoated heater with coated adapter plates.	Inspect the pipe for proper bead formation. Check the melt bead on top of the pipe and along the side of the fitting to verify that the bead is not higher than the shoulder of the fitting. Check that enough pressure has been applied to distinguish the middle bead from the bead on the fitting base. Check for proper alignment between the melt patterns. The melt must be visible all around the pipe and fitting. leak test	Shield the fusion process from wind, blowing snow and excessive heat loss from wind chill. Maintain specified heating tool surface temperature. Do not increase heating tool surface temp. DO not apply additional pressure for any procedure. Time required to obtain proper melt may increase.	Procedure must be performed by individuals qualified under PSE's Operator Qualification Program and Operating Standard 2700.1600 (2009, 2008 and 2007 said Procedure must be performed by individuals qualified under PSE's Operator Qualification Program in the specific task or procedure. Individuals who are not qualified may perform this procedure only if they are continually and directly observed by a qualified person. as specified in Operating standard 2425.2100)	Cooling: once cool to touchable then wait 15 additional minutes.	2011, 2010, 2009, 2008 and 2007 GFP 4600.1030

Time Period	Fusion Types	Fusion Machine	Pipe Material	Pipe Size	Fusion Pressure	Temperature Requirement	Validating Temperature	Pipe Preparation Specification	Final Joint Requirement	Fusing in Cold Weather	General Requirements	Comments	Reference Document
2011 to 2007	Joining pipe by Electro fusion (Coupling)	Electro fusion Unit/control box or Innogaz PE 3408/PE 7410	couples MDPE and HDPE	All 6-inch and 8-inch MDPE-HDPE joints. Final connection of new mains and services to existing 2-inch to 8-inch gas facilities.	N/A	N/A	Inspect the Pressure wells. The only check you can make is for material melt, check for visible molten material at end of fusion in the pressure wells.	All butt fusion coupling shall be at least three pipe diameters, or 12 inches, whichever is greater, away from the squeeze point. For piping that is from a coil, pups from straight pipe shall be butt fused to each coiled piece of pipe, so the electro fusion is done on straight pipe. Check the pipe/fitting/valve for cuts gouges, scrapes removing any section that has a cut gouge, or scrape deeper than 10% of the wall thickness. Cut the pipe ends Square and remove burrs and shavings. Pipe cuts must be clean (saw cuts are not acceptable). Wipe inside and out side of pipe ends with a clean paper towel to remove debris. Isopropyl alcohol (90 or 99%) may be used-wipe and dry the alcohol with a clean towel (avoid air drying) (2008 and 2007 does not specify using alcohol). Make a felt pen mark on each pipe at a depth of half the coupling length. Use the coupling's molded external centerline as a guide. Use an approved scraping tool to scrape the pipe ends that will be covered by the Fusion couple/joint. Remove scraping with a clean towel.	While cooling is in progress, check the coupling for molten material seeping out of ends. Inspect pressure wells for molten material. If material has seeped out of ends or is not present in the pressure wells, the coupling must be cut out and redone. For 2" IPS 10 min cooling, 3" IPS 20 min cooling, 4" IPS 30 min cooling, 6" IPS 30 min cooling and for 8" IPS 35 min cooling required. Leak test.	Fusion may take longer in cooler weather.	Procedure must be performed by individuals qualified under PSE's Operator Qualification Program and Operating Standard 2700.1600 (2009 and 2008 said Procedure must be performed by individuals qualified under PSE's Operator Qualification Program in the specific task or procedure. Individuals who are not qualified may perform this procedure only if they are continually and directly observed by a qualified person. as specified in Operating standard 2425.2100)	Fusion Procedures changed from 2011 to 2010.	2011, 2010, 2009, 2008 and 2007 GFP 4600.1044

Time Period	Fusion Types	Fusion Machine	Pipe Material	Pipe Size	Fusion Pressure	Temperature Requirement	Validating Temperature	Pipe Preparation Specification	Final Joint Requirement	Fusing in Cold Weather	General Requirements	Comments	Reference Document
2011 to 2007	Joining Pipe by Sidewall/saddle Electrofusion	Universal electrofusion unit	sidewall/saddle fittings for 2-inch to 8-inch MDPE and HDPE	2-inch to 8-inch MDPE and HDPE	N/A	N/A	Inspect the Pressure wells. The only check you can make is for material melt, check for visible molten material at end of fusion in the pressure wells.	Clean pipe with paper towel, check pipe for cuts, gouges and scrapes deeper that 10% of the wall thickness. Place the bagged fitting over the pipe to mark the pipe on either side of the fitting to establish the boundaries of the scraped area. Place several marks between the boundary lines as a way to determine the pipe has been completely scraped. Use an approved scraping tool to scrape the area to be fused. Clean loose scrapings off with a paper towel. If the scraping area becomes dirty use Isopropyl alcohol and a clean rag to clean the area.	Allow the fusion to cool in the alignment clamps for the time shown on the bar code labeled on the fitting. While cooling is in progress, check if molten material is visible at the base of the fitting, if yes, the chimney must be cut off of the fitting so that it cannot be tapped. Another fusion must be performed. Allow to cool for an additional time. The Additional time should be equal to the time shown on the bar code label on the fitting. (2009 and 2008 just says remove the clamp when the cooling cycle is complete.)	Fusion may take longer in cooler weather.	Procedure must be performed by individuals qualified under PSE's Operator Qualification Program and Operating Standard 2700.1600 (2009, 2008 and 2007 said Procedure must be performed by individuals qualified under PSE's Operator Qualification Program in the specific task or procedure. Individuals who are not qualified may perform this procedure only if they are continually and directly observed by a qualified person. as specified in Operating standard 2425.2100)		2011, 2010, 2009, 2008 and 2007 GFP 4600.1045

Appendix B-6: Anode Installation on Tracer Wire

The following document was researched and compiled by the Gas System Integrity Department in 2011.

Distribution Integrity Management Program
Design and Construction Research
Anode Installation on Tracer Wire

The purpose of this research is to confirm when PSE or Washington Natural Gas (WNG) began installing anodes on tracer wire. There is risk of the tracer wire corroding when not cathodically protected. This results in increased improper locates or not being able to locate facilities prior to excavation.

Based on the research conducted as documented in Table 1, it was found that the Washington Natural Gas (WNG) Operating Standard in 1970 required tracer wire on plastic mains and services that were installed by direct burial. This is based on the WNG Operating Standard 14.2 with the effective year of 9/1/1975 which cancelled a standard from 1970 which no revisions were indicated for those specific requirements. Not until 1973 were there specific requirements in the WNG Operating Standard 14.5 for polyethylene pipe mains installations to install locating wire with the main.

Effective 9/1/1989, the WNG Operating Standard 14.5 required a one pound magnesium anode to be installed on locating wire at approximately 1,000 feet intervals. This requirement applied to both polyethylene mains and services that were direct buried. Effective 11/11/1988, WNG Quality Assurance Standards 206.5 required a one pound anode to be installed on every 1,000' of tracer wire.

Based on these findings, it can be concluded that tracer wire was being used as early as 1970 and it was not until late 1988 were one pound anodes required to be installed on tracer wire at 1000' intervals. It is most likely that tracer wire installed prior to 1988 is more susceptible to corrosion as they were not cathodically protected.

Table 1. Summary of Tracer Wire and Anode Installation Research

Reference Document	Effective Date	Cancelling Date	Requirement (Mains)	Requirement (Services)
Washington Natural Gas Operating Standards Index 14.5 Developmental Specifications Locator Wire and Detector Tape	08/30/1974	None Specified	4.1 Locator wire or detector tape shall be installed where plastic mains are installed by direct burial method.	5.1 Location wire #14 insulated shall be installed in conjunction with direct burial services.
	09/01/1975	8/30/1970	4.1 Location wire or detector tape shall be installed where plastic mains are installed by the direct burial method.	5.1 Location wire #14 insulated shall be installed in conjunction with direct burial services.
	05/20/1977	9/1/1975	4.1 Location wire or detector tape shall be installed where plastic mains are installed by the direct burial method.	5.1 Location wire #14 insulated shall be installed in conjunction with direct burial services.
	09/01/1989	05/20/1977	4.1 Locator wire shall be installed where polyethylene mains are installed by direct burial. The wire shall be installed in a manner that will facilitate accurate location of gas mains. 4.2 Locator wire shall be cathodically protected by installing a one pound magnesium anode on the wire at approximately 1,000 feet intervals. The anode shall be attached to the locator wire using an approved splice kit.	5.1 Insulated #14 copper locator wire shall be installed with direct burial services. The locator wire shall be installed in a manner that will facilitate accurate location of gas services. 5.2 On services extending from cast iron or steel mains, the locator wire shall be spirally wrapped around the main with a one pound magnesium anode attached. The locator wire shall terminate aboveground, spirally wrapped and taped to the riser. On services extending from polyethylene mains, the locator wire shall be spliced to the main locator wire using an approved splice kit.

Reference Document	Effective Date	Cancelling Date	Requirement (Mains)	Requirement (Services)
Washington Natural Gas Operating Standards Index 14.2 Developmental Specifications Polyethylene Pipe Mains	06/26/1973	None Specified	4.7 Locating tape or insulated locating wire shall be installed with all direct burial polyethylene pipe.	N/A (Standard only for Main)
	06/01/1975	06/26/1973	4.7 Locating tape or insulated locating wire shall be installed with all direct burial polyethylene pipe. Locating wires shall be installed at pipe depth. Locating tapes shall be installed approximately 12" below ground surface.	N/A (Standard only for Main)
	10/24/1979	06/01/1975	4.7 Insulating locating wire shall be installed with all direct burial polyethylene pipe. Locating wires shall be installed at depths specified in Operating Standard 14.5.	N/A (Standard only for Main)
Washington Natural Gas Quality Assurance Standards Index 206.5 Installation Procedure Sacrificial Anode	11/11/1988	None Specified	1. Scope This standard establishes the installation procedure for sacrificial anodes used for the protection against corrosion of…tracer wire. This procedure shall be used whenever this assembly is installed on a facility of the Washington Natural Gas Company. 2.2 The size of anode used shall be determined from the following table: Tracer Wire 1# (per 1000'). 2.4 Attach the anode wire to the item to be protected by …using a wire splice kit to tracer wire.	
Washington Natural Gas Fitter's Manual (1978)	1978	None Specified	(Plastic Pipe Installation under Plastic Main Installation) Insulated locating wire shall be installed with all direct burial polyethylene pipe. Locating wire may be buried at pipe depth or under the pipe. When plastic main is extended from steel main, the locating wire shall be thermally bonded to the steel pipe.	N/A (Applicable to mains only)

See DIM Program files for reference documentation. Research completed in 2011 by Gas System Integrity.

Appendix B-7: Coating Types on Wrapped Steel Pipe (Services)

The following document was researched and compiled by the Standards Department.

Year	Service Sizes (inches)	OD (inches)	Wall Thickness (inches)	Schedule	Material	Coating Type	Field Coating Type	Cathodic Protection	Comments
1956	3/4	1.05	0.113	40	API 5L or ASTM A120 Continuous Weld, Electric Weld or Seamless	Mill applied Coal Tar Enamel; Hot applied coal tar tape such as "Protectowrap"; Pressure sensitive polyvinyl or polyethylene tape such as "Scotchwrap" or "Polyken" or equivalent; or Microcrystalline wax such as Dearborn "No-Ox-Id GG" and No-Ox-Idized reinforced fabric wrapper	No Recorded Info	Section missing from manual	Steel services shall be wrapped unless otherwise specified.
	1	1.315	0.133	40					
	1 1/4	1.66	0.14	40					
	1 1/2	1.9	0.145	40					
	2	2.375	0.154	40					
	3	3.5	0.216	40					
	4	4.5	0.237	40					
	6	6.625	0.25	40					
1960						Removed "Scotchwrap" option of coating	Joints: Bitumastic 50 primer & heated coal tar tape; Fittings and cocks: Hot applied coal tar tape or No Oxide wax; Risers: Plastic tape.	Section missing from manual	
1966	1/2	0.84	0.109	40	API 5L or ASTM A120 Continuous Weld	Mill applied Coal Tar Enamel, high density copolymer polyethylene compound, or thermosetting epoxy resin	Joints: Bitumastic **70** primer & heated coal tar tape; Fittings and valves: Hot applied coal tar tape or No-OX-ID GG 40, **Roskote 612 XM**; Risers: **Bitumastic 70 primer** & plastic tape.	Section missing from manual	Copper tubing or approved plastic pipe may be used for service to a gas light. All pipe shall be wrapped
	3/4	1.05	0.113	40					
	1	1.315	0.133	40					
	1 1/4	1.66	0.14	40					
	1 1/2	1.9	0.145	40					
	2	2.375	0.154	40					
	4	4.5	0.188		API 5L Grade B				
1971								Service from unprotected bare or coated main: insulate, install 3# anode; Service from main under cathodic protection **by impressed current**: don't insulate, don't install anode; Service from main under cathodic protection **by mag anodes**: **install 3# anode**, don't insulate; Partial replacement of service from bare main: insulate, install 3# anode; Twin service from unprotected bare or coated service: **install 17# anode**, **don't** insulate; Twin service from service protected by mag anode: **install 3# anode**, don't insulate	Removed option for copper tubing or plastic pipe for gas lights, no mention of gas lights in standard. All pipe shall be wrapped
1972	1/2	0.57	0.035		ASTM A539	Mill applied Plastic Coating (X-tru Coat)		Service from unprotected bare or coated main: insulate, install 3# anode; Service from main under cathodic protection: don't insulate, don't install anode; Partial replacement of service from bare main: insulate, install 3# anode; Twin service from unprotected bare or coated service: install 3# anode, insulate; Twin service from service protected by mag anode: don't install anode, don't insulate	1/2 inch coiled steel tubing allowed on IP services between 10 psig and 100 psig, pipe required to be straightened prior to installation. All pipe shall be wrapped
	1/2	0.84	0.109	40	API 5L or ASTM A120 Continuous Weld	Mill applied Coal Tar Enamel or Plastic Coating (X-tru Coat)			
	3/4	1.05	0.113	40					
	1	1.315	0.133	40					
	1 1/4	1.66	0.14	40					
	1 1/2	1.9	0.145	40					
	2	2.375	0.154	40					

Year	Service Sizes (inches)	OD (inches)	Wall Thickness (inches)	Schedule	Material	Coating Type	Field Coating Type	Cathodic Protection	Comments
	4	4.5	0.188		API 5L Grade B				
1977						Replaced X-tru Coat with Extruded Polyolefin Coating			1/2 inch coiled steel tubing removed as an option for service
1980								Install plastic pipe from bare steel and cast iron mains, if steel is required insulate from the main and install 3# anode.	
1986	1/2	0.84	0.109	40	API 5L or A53	Mill applied Coal Tar Enamel or Extruded Polyolefin Coating	Joints: Cold applied tape; Fittings: Cold applied mastic; Risers: Plastic tape over a primer		
	3/4	1.05	0.113	40					
	1	1.315	0.133	40					
	1 1/4	1.66	0.14	40					
	1 1/2	1.9	0.145	40					
	2	2.375	0.154	40					
	4	4.5	0.188		API 5L Grade B				

Attached is a document that I (Linda Johnson – Standards Department) created for the Wrapped Steel Service Assessment Program (WSSAP) upon research and review of PSE's historical specifications and standards regarding the practice of steel service installation and cathodic protection. I thought that your departments may be interested in this info as well if you weren't aware of it already. The time frame that this document spans is from 1956 to 1986 (after 1986 the specification and standard specific to steel service design and construction is replaced with an overall steel pipe specification and standard – the assumption is at this time in history most all new services are plastic). Please note for all the columns where there are blanks is an indication that the standard or specification did not change in that year and was the same as the previous standard or specification.

Appendix B-8: Mechanical Fittings

The following document was researched and compiled by the Standards Department.

MECHANICAL COMPRESSION COUPLING FITTINGS

Abstract:

In the last five years there have been several incidents of mechanical compression coupling failures. Most recently, an incident caused by a failed compression fitting in October 2006 in Texas has prompted PSE to evaluate the types of mechanical compression fittings used in our natural gas distribution system and determine our level of risk of an incident occurring in our system. This document provides a summary of field assembled mechanical compression fittings that were installed in our natural gas distribution system based on knowledge we had at the time.

Background:

In October 2006 and subsequently in May 2007 an explosion occurred from a natural gas leak which resulted in the destruction of two homes, four fatalities, and several others injured. The Railroad Commission of Texas conducted an investigation and prepared a final report which determined the gas leak was due to failure of a prebent riser equipped with a non-restraint compression coupling on the end to connect the polyethylene service line. The polyethylene service line separated or pulled out from the compression coupling. Although the exact cause of failure has not been confirmed, the Railroad Commission of Texas report noted there was recent construction activity in the area of the explosion. The Railroad Commission of Texas has since mandated the removal of prebent risers equipped with a non-restraint compression coupling.

As a result of the incident in Texas and others, PHMSA has issued several advisories recommending that every utility review the types of mechanical compression fittings installed in their system.

Summary:

The fitting that failed was a 1” non-restraint compression coupling manufactured by Rockwell which connected a 1” steel gas carrying riser to a 3/4” plastic service. The steel end of the pipe was welded to the coupling and the plastic end of the pipe was inserted into the compression end of the coupling and past the tip of the gasket. The compression nut on the end of the coupling was tightened to create the seal. The Rockwell coupling was considered a non-restraint type of coupling which was not designed with a stiffener and not tested for pull-out strength.

Based on historical standards and specifications, PSE has not installed Rockwell compression couplings in our distribution system. The types of compression or other mechanical fittings that are or have been installed in PSE’s distribution system are listed in Table 1.

Table 1: Compression or Mechanical Fittings used in PSE Distribution System

Approximate Year Installed	Connection	Type of Fitting	Manufacturer	Size	Application	Fitting Tested for Pull-Out Strength
1972 to current	Steel to Steel	Compression Coupling, Cap, Street Tee	Dresser (Style 90)	½”, ¾”, 1”, 1-1/4”, 2”	Join steel service extension to steel service stub	No
1972 to current	Steel to Cast Iron or Steel to Steel	Compression Coupling	Dresser (Style 39, 39-62 (insulated))	4”, 6”, 8”, 12”	Join steel main	No
1972	Steel to Steel	Compression Coupling	Smith-Blair (Rockwell) (insulated)	¾”, 1”, 1-1/4”, 1-1/2”, 2”		No
	Steel to Plastic	Compression Coupling	Continental	5/8” and 1-1/8”	Join plastic service to: 1. steel gas carrying riser; or 2. to steel service tee w/weld outlet	Yes
Late 1970’s to early 1980’s	Plastic to Plastic	Mechanical Fittings (coupling, elbow, tee, reducers)	Amp-Fit	5/8”,1-1/8”,1-1/4”, 2”	Join plastic extension to plastic stub	Yes
1995-current	Plastic to Plastic	Mechanical Fittings (coupling, elbow, tee, cap, reducer)	RW Lyall	5/8” and 1-1/8”	Join plastic extension to plastic stub	Yes
	Steel to Plastic	Steel Punch-It Service Tee with Compression outlet	Continental	5/8” and 1-1/8”	Main to service tie-in	Yes

Approximate Year Installed	Connection	Type of Fitting	Manufacturer	Size	Application	Fitting Tested for Pull-Out Strength
1979 – 1980's	Plastic to Plastic	Repair Coupling	Norton McMurray Manufacturing Company (Normac)	1-1/8", 1-1/4", 2"	Repair to damaged plastic mains	Yes
1970's to early 1980's	Plastic to Plastic	Repair Coupling	Dresser (Posi-Hold)	3",4", 6"	Repair to damaged plastic mains	Yes
1983	Steel to Steel or Steel to Cast Iron	Compression Coupling	Romac (Style 501 (insulated and non-insulated)	Through 12"	Join steel to steel or steel to cast iron pipe	No
1991	Plastic to Plastic	Mechanical Fittings (coupling, tee, reducer, end cap)	Perfection Corporation (Permasert)	5/8", 1-1/8", 1-1/4", 2"	M	Yes
Late 1970's to early 1980's	Plastic to Plastic	Mechanical bolt-on service tee	Amp-fit	5/8", 1-1/8", 1-1/4", 2"	Main to service tie-in	Yes
1998	Plastic to Plastic	Mechanical bolt-on service tee with Lycofit mechanical coupling outlet	RW Lyall	5/8", 1-1/8"	Main to service tie-in	Yes

PSE has never used non-restraint compression couplings to join steel to plastic pipe or plastic to plastic pipe. The fittings used by PSE for these applications are designed with a stiffener for pull-out resistance. The plastic pipe is inserted over the stiffener and a gasket is placed over the top of the plastic pipe and a compression nut is tightened to create the seal. Per the manufacturer's literature the fittings were tested for pull-out strength and meet today's DOT 192.283(b) regulations. The only non-restraint compression couplings PSE has used are for steel to steel applications. Steel pipe is less susceptible to pull-out due to the strength of the steel.

According to PSE personnel during the early 1980's for a short period of time, the 5/8" and 1-1/8" Continental compression couplings were used for joining a steel riser to a plastic service during a shortage of service head adapters, which accounts for approximately 1-2% of the services installed today. The preferred method during routine operation for installing a plastic service from a plastic or steel main was to insert the plastic service into a steel riser casing and install a service head adapter; this practice was confirmed through standard drawings and historical purchase specifications. The more common application for these couplings is to tie-in a PE service to a steel service tee with a weld outlet.

For 1-1/4” or 2” plastic services with a steel gas carrying riser, a manufactured transition fitting was welded to the steel pipe on one end and heat fused to the plastic pipe on the other end. PSE did not use field assembled compression fittings to join plastic to steel pipe for 1-1/4” or 2” services.

Service tees with a compression outlet are commonly used in our distribution system to tie-in 5/8” or 1-1/8” plastic services to a steel or plastic main. This is done by using either a bolt-on tee for a plastic main or a steel punch-it tee for a steel main. Both styles of service tees are designed with a stiffener, gasket and compression nut on the outlet of the tee and are tested for pull-out strength.

Conclusion:

Based on the results of the investigation PSE did not use the non-restraint Rockwell couplings to connect plastic services to steel gas carrying risers and therefore we are at minimal risk for a similar incident occurring. The Continental compression couplings installed in our system are designed with a stiffener used to prevent pullout of plastic pipe and are tested for pull-out strength. In addition, PSE has not experienced failures from plastic pipe pulling out of a compression outlet end of a coupling.

Resources:

- PSE Historical Gas Operating Standards
- PSE Historical Purchase Specifications
- Gas Fitter’s Manual
- PSE Standard Drawings (3D2-211A (1973))
- Discussions with PSE personnel
- Discussion with Atmos Energy

Appendix B-9: Celcon Caps and Delrin Service Tap Tees

The following document was researched and compiled by Gas System Integrity in 2011.

Design and Construction Research

Plexco Service Tee Celcon Polyacetal Caps and Delrin Insert Tapping Tees

On September 6, 2007, PHMSA issued an advisory bulletin ADB-07-01 notifying operators that Plexco service tee caps made with Celcon polyacetal and Delrin insert tap tees have been added to the list of materials that are susceptible to premature brittle-like cracking. As indicated in this advisory bulletin, the brittle-like cracking is dependent on the resin, pipe processing, and service conditions.

Plexco Service Tee Celcon Polyacetal Caps

In addition to PHMSA's advisory bulletin, Performance Pipe (Plexco) issued clarification and guidance for the concern with Plexco Celcon polyacetal caps. It states that Plexco yellow tapping tees before 1996 used Celcon caps which were designed to be hand tightened and not tightened with a wrench. Caps that were over tightened by wrench could fail thus the problem was not the material but how it was installed. It was not until after 1996 when Plexco stopped manufacturing service tee caps with Celcon and switched to polyethylene. Celcon caps continued to be manufactured after 1996 through March 2000 at the request of specific customers. Customers who did not specifically request Celcon received polyethylene.

PSE has purchased and installed Plexco service tees. Performance Pipe has indicated that they began using the Celcon material on service tee caps between 1982 and 1983 and began using PE caps in 1996 unless customers specifically requested the Celcon caps. PSE's historic purchase specification polyethylene self tapping service tees does not specify Celcon caps. Purchase order records also did not contain this level of detail. Below is a list of MID's associated to service tees and their purchase order descriptions in 1998. Performance Pipe indicated that the service tees are tracked as a unit inclusive of the cap, so the service tees most likely were treated similarly when PSE received the parts.

MID 7800695
TEE TAPPING 2" IPS X 1/2" CTS BUTT FUSION PE 2406 YELLOW
W/ O.80 CUTTER PER WNG SPEC 257.1

MID 7800693
TEE TAPPING 1-1/4"IPS X 1/2"CTS BUTT FUSION PE 2406 YELLOW
W/0.80 CUTTER PER WNG SPEC 257.1

MID 7800699
TEE TAPPING 4"IPS X 1/2"CTS BUTT FUSION PE 2406 YELLOW
W/ 0.80 CUTTER PER WNG SPEC 257.1

According to the Washington Natural Gas's (WNG) Quality Assurance Standards Index 257.6 Approved Materials List Polyethylene Fusion Fittings with the effective date 08/19/1993 (cancelling date 01/10/1990), it lists Plexco as the approved manufacturer under Self Tapping Service Tee. The same standard with the effective date 09/08/1995 (cancelling date

08/19/1993) lists the approved manufacturer(s) and material. Under Self Tapping Service Tee, Plexco / PE 2406 / PE3408 is listed.

Delrin Insert Tapping Tees

Based on the information summarized below, PSE has not purchased or installed Delrin Insert Tapping Tees.

Delrin insert polyethylene tapping tees, originally installed in the 1970s, are a tapping tee with a white acetyl material called Delrin inserted as a threaded sleeve to contain a self-tapping steel cutter and a black cap. These tapping tees are prone to leakage due to premature cracking of the Delrin acetyl sleeve.

PSE has confirmed with the American Gas Association (AGA), Performance Pipe, and Gene Palermo (who worked on DuPont Aldyl products) information regarding Delrin tapping tees. The DuPont Company began selling Service Punch Tees with the Delrin insert around 1970 and then changed to a PE overcap design around 1983 for their Service Punch Tee. Only the DuPont Company sold Service Punch Tees made with a Delrin insert. DuPont only made Delrin insert Service Punch Tees for Aldyl "A" pipe and fittings, which was an MDPE or PE 2306/PE 2406 material.

Based on these findings, PSE did not purchase or install Delrin insert tapping tees as PSE has only purchased and installed HDPE pipe including DuPont Aldyl HD (HDPE 3406) products during that timeframe and PSE did not start installing MDPE 2406 until 1996.

See DIM Program files for source documentation.

Appendix B-10: Gas Quality

The following is a copy of Section 3.1 Gas Quality at Receipt Points from the Williams Northwest Pipeline Gas Quality Tariff Provisions as provided on http://www.northwest.williams.com/NWP_Portal/.

GENERAL TERMS AND CONDITIONS
3. QUALITY

3.1 Gas Quality at Receipt Points. All Gas delivered by Shipper to Transporter shall conform to the applicable specifications in either Section 3.1(a) or Section 3.1(b). As used in this section, the La Plata Facilities are defined as those facilities commencing at a measurement facility downstream of the discharge side of Northwest's La Plata B compressor station southward to the Blanco Hub, including the La Plata A compressor station and certain plant interconnects, all located in southern Colorado and northern New Mexico. (a) All Gas delivered by Shipper to Transporter at Receipt Points not connected to the La Plata Facilities shall conform to the following specifications:

(1) Hydrocarbon Liquids and Liquefiables: The hydrocarbon dew point of the gas delivered shall not exceed fifteen degrees Fahrenheit at any pressure between 100 psia and 1,000 psia as calculated from the gas composition and shall be free from hydrocarbons in the liquid state. At all times, any and all liquid or liquefiable hydrocarbons, or any other constituent or by-product, recovered from the gas by Transporter, after delivery of gas to Transporter shall be and remain the exclusive property of Transporter, except as specified in Section 20 of the General Terms and Conditions.

(2) Hydrogen Sulfide and Total Sulfur: The gas shall contain not more than one quarter grain of hydrogen sulfide per one hundred cubic feet and not more than five grains total sulfur per one hundred cubic feet.

(3) Carbon Dioxide and Total Nonhydrocarbons: The gas shall contain not more than two percent by volume of carbon dioxide and shall contain not more than three percent by volume of combined nonhydrocarbon gases including, but not limited to, carbon dioxide, nitrogen and oxygen, except as otherwise provided in Section 3.5.

(4) Dust, Gums, etc.: The gas shall be commercially free from objectionable odors (excluding odorant added to natural gas for safety reasons or to comply with federal and/or state regulations), solid matter, dust, gums, and gum forming constituents, or any other substance which interferes with the intended purpose of merchantability of the gas, or causes interference with the proper and safe operation of the lines, meters, regulators, or other appliances through which it may flow.

(5) Heating Value: The total gross heating value of the gas deliverable hereunder shall not be less than 985 Btu.

(6) Oxygen: The gas shall not contain in excess of two-tenths of one percent by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

(7) Temperature: The temperature of the gas at the point of delivery shall not exceed one hundred twenty degrees Fahrenheit.

(8) Water: The gas delivered shall be free from liquid water and shall not contain more than seven pounds of water in vapor phase per million cubic feet.

(9) Mercury: The gas shall be free from any detectable mercury.

(10) Toxic or Hazardous Substance: The gas shall not contain any toxic or hazardous substance in concentrations which, in the normal use of the gas, may be hazardous to health, injurious to pipeline facilities, or be a limit to merchantability or be contrary to applicable government standards.

(11) Bacteria: The gas, including any associated liquids, shall not contain any microbiological organism, active bacteria or bacterial agent capable of causing or contributing to: (i) injury to Transporter's pipelines, meters, regulators, or other facilities and appliances through which such gas flows or (ii) interference with the proper operation of the Transporter's facilities. Microbiological organisms, include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (ACB). When bacteria or microbiological organisms are considered a possibility, Shipper(s) desiring to Nominate such gas, upon Transporter's request, shall cause such gas to be tested for bacteria or bacterial agents utilizing the American Petroleum Institute test method API-RP38 or other acceptable test method as determined by both parties.

Appendix B-11: Bolt-on Tees

THE WORD.

PUGET SOUND ENERGY
The Energy To Do Great Things

January 2010 | Standards Department | Issue 264

Bolt-On Tee Failure Analysis

By Nancy Wong. Contact Al Cantey (81-5875).

Mechanical bolt-on service tees are used to run a service and have been installed since the late 1970s. Bolt-on tees are easier to install and take much less time to install than fusion service tees. Through the Materials Failure Analysis Program, Standards has been tracking bolt-on tee failures and has found a number of failures from older vintage bolt-on tees. This has prompted Standards to create an independent failure analysis project to determine the root cause of failure.

Figure 1: Pipe Surface Where Saddle Makes Contact

Under this evaluation, the 34 bolt-on tees that failed between 2008 and 2009, and that were installed between 1977 and 2003, were visually inspected, leak tested, and disassembled. Visual inspection of the bolt-on tees revealed that external defects were very limited. All the bolt-on tees, however, did leak after performing a pressure test at various locations. Most commonly, the leak was at the saddle and the interface of the two halves of the bolt-on tee. The bolt-on tees were then disassembled for further analysis and significant scratches and gouges were found on the pipe surface where the saddle makes contact with the pipe, including over the O-ring seal (see *Figure 1*).

Figure 2: Bolt-On Tee Saddle

Based on this detailed analysis, it was concluded that the root cause of failure was due to surface defects in the pipe surface that weakened the integrity and seal of the O-ring over time (see *Figure 2*).

As a result of this analysis, it is very important to remember that when installing bolt-on tees, the pipe surface must be clean, as well as scratch and gouge free. Please refer to *Gas Field Procedure* 4575.1040, “Installing Bolt-On Service Tees,” for details.

New Style Copper Pole Ground Plate

By Ryan Wieder (81-3954)

New Copper Ground Plate (MID 8969401) on Left and Current Model on Right

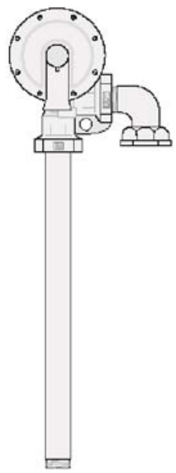
A new copper ground plate design (**MID 8969401**) by Harger Lightning & Grounding has been approved. It has a 1-1/3-inch hole in 3 corners. The ground plate has the required 288 square inches of surface area. It is similar in size and is installed onto the pole butt in the same manner as the existing ground plates, in accordance with *Standard* 6014.1000, "Overhead System Grounds."

Instead of attaching the ground wire to the split bolt under the pole butt, for the new ground plate design, the ground wire is now attached to the plate on the side of the pole once the plate is bent around the pole butt. The new ground plate design can be packaged more compactly to reduce shipping costs and shelf space.

Appendix B-12: Leak Cause Code I –Non-Exposed

New Regulator to be Used with the Residential Regulator Loop Assembly

By Namrata Shrivastava (81-3723). Also contact Matt Eldridge (81-3796).



Residential Regulator Loop Assembly
(MID 9995954)

Please be aware that there is an upcoming change to the Residential Regulator Loop Assembly (**MID 9995954**).

Currently, the following two approved regulators can be used interchangeably for this MID:

- Fisher HSR
- American Meter 1213B2

Standards & Compliance has approved a different American Meter regulator, the 1813C, to replace the 1213B2. The 1813C regulator performs better than the 1213B2 regulator. It is also cost comparable and interchangeable with the American Meter 1213B2.

This change will become effective once the current stock of the 1213B2 regulators is depleted, possibly sometime in April or May.

LEAKS Upgrade Ready for Installation

By Gary Swanson (89-6811)

An upgraded version of LEAKS is ready for installation. You may install the new version by running: **X:\#Config\LMS\InstLMS.bat**

The upgrade should take about 15 seconds. If you have problems, please contact the Help Desk at 81-2020. See below for features.

Main Project Screen (when creating a new leak):

- "Equipment ID," a required field for leaks reported by PSE or contractor personnel. See *Gas Operating Standard* 2625.1100, "Leakage Survey Program." ***Please enter only the number.***
- For the "Job" field, a notification or order number can now be entered for tracking purposes.
- For the "Replacement Planned" field, if the leak is associated with a planned main replacement job, enter "Y." This allows an additional six months for the completion of the replacement.

Work Order Details Screen (when updating a work order):

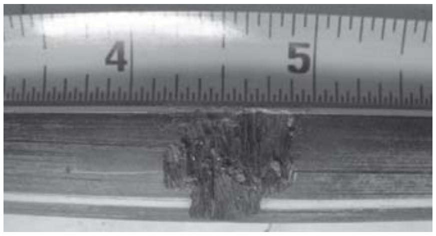
- "Equipment ID," located next to the responder's name, is a required field on all work orders. See *Gas Operating Standard* 2625.1300, "Leakage Action Program." ***Please enter only the number.***
- New definitions have been added to the leak cause codes to better describe the cause of the leak.
- The "I" leak code has been added. It stands for "nonexposed pipe - replacement/retirement when pipe is not exposed."
- Supervisors, please review the new Leak Cause codes with your responders. Leak Work Order (PSE Form 1449) and Leak Codes (PSE Form 2022) have been updated, are available for ordering, and can be viewed online at:

http://pseweb/forms/locator/locator.aspx

Appendix B-13: Leak Cause Code Clarification

Leak Cause Code Clarifications

By Jae Pfeffer (81-3715)



Cause Code C:
Animal Damage

Did you know that the cause code selected on a Leak Work Order is used by other departments? Standards is one of those departments that uses the cause code to decide which failures need to be reported to the Washington Utilities and Transportation Commission and for information during the process of analyzing the failure.

Cause code selection can be challenging. Below is a description of each and some examples.

B. Excavation is the code used to indicate any sort of damage caused by digging.

- Dig-ins. Examples: “Broken,” “broken and blowing,” and “found service bent over and taped.”
- Damage caused by accident when the trench was open. Example: A backhoe that clips a piece of asphalt that flies into an open trench and damages a pipe.
- Obvious damage caused by someone, belowgrade, that is discovered later, most likely while digging. Example: Finding a homemade repair.

C. Natural Force is the code used to indicate damage because of nature. Generally you will not be able to sue someone for negligence.

- Animal damage. Example: Hole in PE caused by rat.
- Vegetation. Example: Crushed by tree roots.
- Ground settling.

Cause Code D:
Service Tee Cap with
Damage from Overtorquing
(wrench marks visible)

D. Operations is the code used to indicate an incorrect installation or poor workmanship.

- Incorrect installation. Example: “EFV installed backwards.”
- Poor workmanship. Example: “Replaced leaking service tee cap that was overtightened and cracked.”

E. Material or Welds is the code used to identify a fusion or weld repair/replacement, even if it could be coded as something else. This code also includes any part that fails in the system due to obvious manufacturer defect.

- Fusion. Examples: Cracked fuse, uneven fusion bead, and insufficient rollback.
- Weld. Examples: Girth welds, seam welds, and cracked welds, regardless if they were done at the factory or in the field.
- Material. Examples: Rock impingement or crack on DuPont pipe and part that has a leak because of a manufacturing defect that may not have been obvious when the part was installed.

F. Other is the code that should only be used when a part has exceeded its service life or you really do not know why it failed and it fits in no other category.

- Exceeded service life.

Cause Code E:
Rock Impingement or
Crack on DuPont Pipe

G. Equipment is the code used when equipment leaks and it is repaired or replaced.

- Repaired equipment by operating, tightening, and/or greasing. Examples: “Greased valve to zero leak,” “tightened cap,” and “redoped threads.”
- Replacement of parts that are not aged or not an apparent installation problem. Examples: “Replaced bolt-on tee”and “leaking valve replaced.”

H. Outside Force Damage is the code used when there is aboveground damage that has been caused by someone. Typically you could hold someone responsible for the damage.

- Accidental damage. Examples: “Car backed into MSA” and someone sat on manifold and broke it.
- Damage from some other event not related to excavation. Examples: House fire and MSA pulled loose because it was used as a garden hose stand.

I. Non-Exposed Pipe is the code used when the leak is repaired without finding the specific leaking section or component.

- Main replacement jobs that zero leaks.
- Repair by replacing the entire service.

PSE Leak Cause Codes (Reference Sheet with Examples)

By Ron Easley (81-3721)

The following table is provided as a reminder of the PSE defined cause codes in the left column and a clarification of the code in the right column with some examples. A cause code is required for every Leak Work Order completed.

Please keep this removable insert as a desk or field reference. If you have any questions or would like to discuss the application of cause codes, please contact Jae Pfeffer at 81-3715 or Ron Easley at 81-3721.

A leak is an unintentional escape of gas through a hole or crack in the pipeline or pipeline component (valve, tee, etc.).

Leak Cause Codes Information (as listed in Form 2022)	Examples
B. Excavation - Damage caused by earth moving equipment, tools or vehicles including leaks from damage by operator's personnel or contractor, or people not associated with the contractor.	Anything trench-related (i.e., even a back-hoe driving by a trench causing an asphalt chunk to fall on a pipe and cause a leak fits in this category). Anything that would be considered third-party damage.
C. Natural Force - Earth movements, earthquakes, landslides, lightning, heavy rains/floods, washouts, flotation, scouring, temperature, frost heave, frozen components and high winds.	Anything that cannot be attributed to any human cause or decision or that has no person or group that could be held legally liable (i.e., damage caused by gnawing voles fits in this category, a poorly placed unstable piece of equipment that tips over on to aboveground piping does not).
D. Operations - Inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error.	Not following proper procedures or standards for pipeline inspection, maintenance, or construction (i.e., leaks caused by improper: meter set change-out, backfill and compaction, service tee tapping, etc.).
E. Materials or Welds - Failed fuses, rock impingement, faulty wrinkle bends, faulty field welds and damage sustained in transportation to the construction or fabrication site, defect in the pipe material, component or the longitudinal weld or seam due to faulty manufacturing procedures.	This includes leaks of any cause types listed to the left, or other similar origins, when all proper procedures and standards were followed (i.e., anything where the cause is linked to a faulty material).
F. Other - Exceeding the service life, material deterioration (other than corrosion), any of the other causes not attributable to the other identified causes.	
G. Equipment - Malfunction of control/relief equipment including valves, regulators or other instrumentation; stripped threads or broken pipe couplings on nipples, valves or mechanical couplings; or seal failures on gaskets, O-rings, seal/pump packing or a similar leak.	Any leak caused by failure of any of the equipment listed to the left, or other similar devices. Any leak that can be repaired by maintenance procedures that do not replace any component, or add any device to the system (i.e., greasing valves, redoping pipe threads, tightening bolts or fittings).
H. Outside Force Damage - Fire, explosion and deliberate or willful acts, such as vandalism.	Intentional as well as unintentional acts (i.e., vehicular accidents, damage by the general public).
I. Non-Exposed Pipe - Replacement/Retirement when pipe is not exposed.	Hole-hogging or direct burying a new gas service as a replacement for a leaking one, main replacement jobs which retire any leaking main or service.
A corrosion leak is one in a pipeline or pipeline facility resulting from galvanic, bacterial, chemical, stray current action, or other corrosive actions. Common indicators of corrosion are pitting on metallic pipe and graphitization of cast iron.	
J. Corrosion, Disbonded STW - Any leak resulting from corrosion on pipe with disbonded wrap.	
K. Corrosion, Low PSP STW - Any leak resulting from corrosion on STW pipe with a PSP reading less than -.85 volts.	
L. Corrosion, Unknown STW - Any leak resulting from corrosion on STW pipe with proper bonding and PSP reads.	
M. Corrosion, Bare Pipe - Any leak resulting from corrosion on uncoated pipe.	

Appendix C: Risk Evaluation and Prioritization

Appendix C-1: Risk Evaluation and Prioritization Plan

1. Scope

This document defines the methodology to be applied for the risk assessment and determination of when appropriate mitigative measures are required for the gas distribution system. This mitigation plan applies to specific assets within facility types and primary threats and sub-threats. Facility types include mains, services, MSAs, valves, farm taps, regulator stations, and propane peak-shaving plant and distribution system.

2. Responsibilities

2.1 The *Manager Gas System Integrity* shall be responsible for:

2.1.1 Overall system risk evaluation and prioritization including:

2.1.1.1 Ensuring system risks are evaluated, prioritized, and validated annually as described in Section 4.

2.1.1.2 Ensuring any modifications to the System Risk Evaluation and Prioritization Matrix, mitigation actions or mitigation category thresholds are documented as required in Section 7.

3. General

3.1. The System Risk Evaluation and Prioritization Matrix (Matrix) is comprised of a list of assets, primary threats and sub-threats, and relative scores for each asset and sub-threat.

3.1.1. The Matrix evaluates the assets within a facility type by material type, vintage, operating pressure, and specific facility characteristics. Assets that have similar characteristics are evaluated together for which similar mitigative measures would be effective in reducing risk. These characteristics could include physical pipe characteristics and/or environmental factors.

3.1.1.1. These facility types include mains, services, MSAs, valves, farm taps, regulator stations, and propane peak-shaving plant and distribution system.

3.1.1.2. Material types for mains and services include bare steel, wrapped steel, and polyethylene.

3.1.1.3. Vintages include 1971 and older and 1972 and newer for wrapped steel, 1985 and older and 1986 and newer for polyethylene, and older and newer vintages for valves.

3.1.1.4. Operating pressures include low pressure, intermediate pressure, and high pressure.

3.1.1.5. Specific facility characteristics include facilities being installed in casing or in wall-to-wall paving, or unintentionally becoming buried or shallow as well as other characteristics.

3.1.2. The primary threats and corresponding sub-threats that are evaluated are listed in Table 1.

Table 1. Primary Threats and Sub-Threats

Primary Threat	Sub-Threat
Corrosion	External Corrosion
	Internal Corrosion
	Atmospheric Corrosion
	Stray Current
Natural Forces	Seismic Activity
	Earth Movement/Landslide
	Frost Heave
	Flooding
	Over-pressure due to snow/ice blockage
	Tree Roots
	Animal Damage
	Lightning
Excavation Damage	Failure to Call
	Improper Excavation Practice
	Facility Not Located or Marked
	One-call Notification Center Error
	Locating Error
	Facility Not Platted/Other
Other Outside Force Damage	Vehicle Damage
	Vandalism/Tampering
	Electrical Faults
	Structure Fire
Material, Weld or Joint Failure	Brittle-like Cracking Failure
	Fusion Failure
	Weld Failure
	Mechanical Fitting Failure
Equipment Failure	Celcon Service Tee Caps
	Valves
	Regulator Failure
Incorrect Operations	Operating Error

Primary Threat	**Sub-Threat**
	Pipe Bored Through Sewers
Other	Other

3.2 The Matrix is used to evaluate and rank the risks in the distribution system.

3.3 The evaluation and ranking are based on assigning a relative score for the likelihood of failure and the consequence of failure. The product of the two scores is the total risk score used to determine the risk of the overall asset and threat.

3.4 Assets and/or threats that meet the criteria for additional and accelerated actions are further evaluated to determine if existing mitigative measures are adequately addressing risks or if additional and accelerated actions are needed.

4. Prioritizing System Risks

4.1. The Matrix shall be used to perform a system risk assessment in order to prioritize system risks. The first comprehensive risk ranking of identified assets and threats was performed in 2011.

4.1.1. The Matrix calculates a total relative score (TOT) for each asset under each sub-threat based upon the following factors:

4.1.1.1. Likelihood of failure (FOF) and

4.1.1.2. Consequence of failure (COF).

4.1.2. The relative scores are assigned in accordance with Table 2 and Table 3.

Table 2. Relative Score for Likelihood of Failure

Scoring Description	**Relative Score**
Not Applicable	0.0
Likely to occur almost never	0.5
Likely to occur occasionally	1.0
Likely to occur sometimes	1.5
Likely to occur frequently	2.0
Likely to occur more than frequently	2.5
Likely to occur most frequently	3.0

Table 3. Relative Score for Consequence of Failure

Scoring Description	Relative Score
Not Applicable	0.0
Little or no consequence	0.5
Little to moderate consequence	1.0
Moderate consequence	1.5
Moderate to high consequence	2.0
High consequence	2.5
Highest consequence	3.0

4.1.3. The relative score for the likelihood of failure and consequence of failure are determined using Subject Matter Expert (SME) input and system knowledge.

4.1.3.1. System knowledge consists of design and construction information, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

4.1.3.2. The relative score for likelihood of failure considers the following:

4.1.3.2.1. Data supporting whether the failure has occurred before;

4.1.3.2.2. Data supporting how frequent failure has occurred;

4.1.3.2.3. SME input of known failures or the potential for failure;

4.1.3.2.4. SME input of how frequently failure occurs or could occur;

4.1.3.2.5. SME input of how existing mitigative measures impact likelihood;

4.1.3.3. The relative score for the consequence of failure considers the following:

4.1.3.3.1. Data supporting the leak grade (or severity) of known failures;

4.1.3.3.2. Data supporting the operating pressure of the facility of known failures;

4.1.3.3.3. Data supporting the proximity to buildings of known failures;

4.1.3.3.4. Data supporting the consequence of gas migration;

4.1.3.3.5. SME input of the consequence of known failures;

4.1.3.3.6. SME input of the potential consequence relative to severity of failure;

4.1.3.3.7. SME input of the potential consequence relative to operating pressure;

4.1.3.3.8. SME input of potential consequence relative to proximity to buildings;

4.1.3.3.9. SME input of the potential for gas migration;

4.1.3.3.10. SME input of safe venting;

4.2. The total relative score (TOT) for each asset and sub-threat is determined from the relative score of likelihood of failure (FOF) and consequence of failure (COF) in accordance with the following formula:

[FOF] x [COF] = [TOT]

4.3. The total risk score is determined from the sum of the total relative scores of each asset and sub-threat according to the following formula:

$$\sum[\text{TOT}] = [\text{Total Risk Score}]$$

4.4. An adjusted risk score is used to evaluate the risk only attributed to the physical properties of the facilities and not by external factors. The adjusted risk score is determined from the total risk score, the total relative score from the Excavation Damage primary threat, and the total relative risk score from the Sewer Cross Bore sub-threat according to the following formula:

$$[\text{Total Risk Score}] - \sum[\text{Excavation Damage TOT}] - [\text{Sewer Cross bore TOT}] = [\text{Adjusted Risk Score}]$$

4.5. A system risk assessment utilizing the Matrix shall be performed each calendar year.

4.6. The Matrix shall be validated based on SME input and data.

4.7. The Matrix shall be updated annually to incorporate new and/or revised data, and newly identified assets and sub-threats.

4.8. Prioritization of assets is based on the adjusted risk score within each facility type and may be adjusted based on SME review.

5. System Risk Mitigation Categories

5.1 The mitigation categories shall be determined based on the following criteria except where SME review determines an alternate mitigation category is appropriate. Where SME's determine an alternate mitigation category is appropriate, the basis for this determination shall be documented for future reference. The following are the mitigation categories and the mitigation thresholds that prompt specific action to be taken:

5.1.1 Risk Priority 1 – Assets based on a combination of threats, assets based on specific threats, and primary threats and sub-threats that meet the following criteria shall require further action to mitigate risk:

5.1.1.1 Assets within a facility type that have an adjusted risk score > the average adjusted risk score of the assets within a facility type.

5.1.1.2 Assets within a facility type where the criteria specified in Section 5.1.1.1 is not met, but any specific threats excluding the primary threat Excavation Damage and sub-threat Sewer Cross Bores that have a TOT relative score of 4.0 or more.

5.1.1.3 Primary threats or sub-threats that have a TOT relative score of 4.0 or more for more than 75% of the assets in any one facility type.

5.1.2 Risk Priority 2 - Assets based on a combination of threats, assets based on specific threats, and primary threats and sub-threats that do not meet the criteria in Section 5.1.1 shall not require further action unless SME review determines further action is warranted.

5.2 The mitigation categories and mitigation category thresholds may change as specified in Section 7.

6. Mitigation Plan

6.1 Assets and threats shall be mitigated based on their mitigation category as described in Table 4.

6.2 The mitigation actions may change as specified in Section 7.

Table 4. Mitigation Plan

Mitigation Category	Mitigation Plan Description
Risk Priority 1	• Assets and threats shall be mitigated in accordance with Distribution Integrity Management (DIM) Plan Section 8 Mitigative Measures and Additional and Accelerated Actions to Reduce Risk.
Risk Priority 2	• Perform normal operation and maintenance activities unless SME review warrants additional and accelerated actions.

7. Measure Performance, Monitor Results, and Evaluate Effectiveness

7.1 PSE will measure the performance in accordance with Section 9 Measure Performance, Monitor Results, and Evaluate Effectiveness in the DIM Plan to evaluate opportunities to refine the Matrix.

8. Records

8.1 Records summarizing the results of each annual risk assessment shall be maintained and incorporated into the distribution integrity management program.

8.2 Records demonstrating mitigation plans were implemented as required by this Plan shall be maintained.

Appendix C-2: Risk Evaluation and Prioritization Results

Distribution Integrity Management Program
Risk Evaluation and Prioritization Matrix

Frequency of Failure (FOF) or Pontential Failure:
0.5 - Occurs Almost Never
1.0 - Occurs Occasionally
1.5 - Occurs Sometimes
2.0 - Occurs Frequently
2.5 - Occurs More than Frequently
3.0 - Occurs Most Frequently

Consequence of Failure (COF) or Potential Consequence:
0.5 - Little or No Consequence
1.0 - Little to Moderate Consequence
1.5 - Moderate Consequence
2.0 - Moderate to High Consequence
2.5 - High Consequence
3.0 - Highest Consequence

Total Relative Score (TOT):
TOT = FOF x COF

Threats and Sub-Threats

	Asset	Corrosion: External Corrosion			Corrosion: Internal Corrosion			Corrosion: Atmospheric Corrosion			Corrosion: Stray Current			Natural Forces: Seismic Activity			Natural Forces: Earth Movement / Landslide			Natural Forces: Frost Heave			Natural Forces: Flooding			Natural Forces: Over-pressure due to snow/ice blockage		
		FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT
Main	*Main*																											
	Bare Steel (LP - IP)	3.0	1.5	4.5	0.5	1.5	0.8				1.0	1.5	1.5	1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	1971 and Older Wrapped Steel (LP - IP)	2.0	1.5	3.0	0.5	1.5	0.8				1.0	1.5	1.5	1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	1972 and Newer Wrapped Steel (LP - IP)	1.0	1.5	1.5	0.5	1.5	0.8				1.0	1.5	1.5	1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	1985 and Older Polyethylene (LP - IP)													1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	1986 and Newer Polyethylene (LP - IP)													1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	Wrapped Steel (HP)	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	1.0	1.0	1.0			
	Wrapped Steel in Casing	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.5	1.5	1.0	1.5	1.5	1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	Shallow													1.0	1.5	1.5	1.0	1.5	1.5	0.5	1.5	0.8	1.0	1.0	1.0			
	Wall-to-Wall Paving/HOS													1.0	3.0	3.0	1.0	3.0	3.0	0.5	3.0	1.5	1.0	1.0	1.0			
Service	*Service*																											
	Bare Steel (LP - IP)	3.0	2.0	6.0	0.5	2.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	1971 and Older Wrapped Steel (LP - IP)	2.0	2.0	4.0	0.5	2.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	1972 and Newer Wrapped Steel (LP - IP)	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	1985 and Older Polyethylene (LP - IP)							1.0	1.0	1.0				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	1986 and Newer Polyethylene (LP - IP)							0.5	1.0	0.5				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	Wrapped Steel (HP)	1.0	3.0	3.0	0.5	3.0	1.5	1.0	2.0	2.0	0.5	3.0	1.5	1.0	3.0	3.0	1.0	3.0	3.0	0.5	3.0	1.5	1.0	1.0	1.0			
	Idle Riser							1.5	1.0	1.5				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	Wrapped Steel in Casing	1.0	2.0	2.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	Shallow							0.5	1.0	0.5				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	1.0	1.0			
	Wall-to-Wall Paving/HOS													1.0	3.0	3.0	1.0	3.0	3.0	0.5	3.0	1.5	1.0	1.0	1.0			
MSA	*MSA*																											
	Residential MSA				0.5	2.0	1.0	1.0	1.0	1.0				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0
	Buried MSA	3.0	2.5	7.5	0.5	2.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0
	Commercial and Industrial MSA				0.5	1.0	0.5	1.0	2.0	2.0				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0
	Sidewalk and Street Vault Regulators	2.0	2.5	5.0	0.5	2.0	1.0	1.5	2.0	3.0	1.0	2.0	2.0	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5
	Aboveground Regulators	2.0	2.5	5.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5
	MSA with Insufficient Traffic Protection				0.5	1.0	0.5	1.0	2.0	2.0				1.0	2.0	2.0	1.0	2.0	2.0	0.5	2.0	1.0	1.0	2.0	2.0	1.0	2.0	2.0
Valve	*Valves*																											
	Newer Valves (STW and PE)	1.0	2.0	2.0	0.5	2.0	1.0				1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	1.0	1.0			
	Older Valves (STW)	1.0	2.0	2.0	0.5	2.0	1.0				1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	1.0	1.0			
	Double IF Valves	2.0	2.0	4.0	0.5	2.0	1.0				1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	1.0	1.0			
FT	*Farm Tap*																											
	Single Service Farm Tap	1.0	2.5	2.5	0.5	2.5	1.3	1.5	2.5	3.8	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	1.0	1.0	1.0			
	Modified Farm Tap (Farm Tap on Riser)				0.5	3.0	1.5	1.0	3.0	3.0				1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	1.0	1.0	1.0	3.0	3.0
RS	*Regulator Stations*																											
	Gate Station, Town Border Station, Limiting Station	0.5	2.5	1.3	0.5	2.5	1.3	1.0	2.5	2.5	1.5	2.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5	1.0	3.0	3.0
	HP-IP District Regulator Station	0.5	2.5	1.3	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.0	2.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5			
	IP-LP District Regulator Station	0.5	2.5	1.3	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.0	2.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5			
Pro	*Propane Peak-Shaving Plant and Distribution System*																											
	Propane Distribution System - Sumner	1.0	2.5	2.5	0.5	2.5	1.3	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	0.5	2.5	1.3	1.0	1.0	1.0	0.5	2.5	1.3
	Swarr Propane-Air Plant	1.0	1.0	1.0	0.5	1.0	0.5	0.5	1.0	0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.5	1.0	1.5	0.5	1.0	0.5	2.0	0.5	1.0	0.5	1.0	0.5

	Asset	Natural Forces: Tree Roots			Natural Forces: Animal Damage			Natural Forces: Lightning			Excavation Damage: Failure to Call			Excavation Damage: Improper Excavation Practice			Excavation Damage: Facility Not Located or Marked			Excavation Damage: One-call Notif. Center Error			Excavation Damage: Locating Error			Excavation Damage: Facility Not Platted/Other		
		FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT	FOF	COF	TOT
Main	*Main*																											
	Bare Steel (LP - IP)	1.0	1.5	1.5				1.0	2.0	2.0	3.0	2.0	6.0	3.0	2.0	6.0	2.0	2.0	4.0	1.0	2.0	2.0	2.0	2.0	4.0	1.0	2.0	2.0
	1971 and Older Wrapped Steel (LP - IP)	1.0	1.5	1.5				1.0	2.0	2.0	3.0	2.0	6.0	3.0	2.0	6.0	2.0	2.0	4.0	1.0	2.0	2.0	2.0	2.0	4.0	1.0	2.0	2.0
	1972 and Newer Wrapped Steel (LP - IP)	1.0	1.5	1.5				1.0	2.0	2.0	3.0	2.0	6.0	3.0	2.0	6.0	2.0	2.0	4.0	1.0	2.0	2.0	2.0	2.0	4.0	1.0	2.0	2.0
	1985 and Older Polyethylene (LP - IP)	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	3.0	2.0	6.0	3.0	2.0	6.0	2.0	2.0	4.0	1.0	2.0	2.0	2.0	2.0	4.0	1.0	2.0	2.0
	1986 and Newer Polyethylene (LP - IP)	1.0	1.5	1.5	1.0	2.0	2.0	1.0	2.0	2.0	3.0	2.0	6.0	3.0	2.0	6.0	2.0	2.0	4.0	1.0	2.0	2.0	2.0	2.0	4.0	1.0	2.0	2.0
	Wrapped Steel (HP)	0.5	2.0	1.0				1.0	2.5	2.5	3.0	2.5	7.5	0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.5	1.3	0.5	2.5	1.3
	Wrapped Steel in Casing							1.0	2.0	2.0	3.0	1.0	3.0	3.0	1.0	3.0	2.0	1.0	2.0	1.0	1.0	1.0	2.0	1.0	2.0	1.0	1.0	1.0
	Shallow	1.0	1.5	1.5	1.0	2.0	2.0	1.0	2.0	2.0	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	Wall-to-Wall Paving/HOS	0.5	3.0	1.5	0.5	3.0	1.5	1.0	3.0	3.0	3.0	3.0	9.0	3.0	3.0	9.0	2.0	3.0	6.0	1.0	3.0	3.0	2.0	3.0	6.0	1.0	3.0	3.0
Service	*Service*																											
	Bare Steel (LP - IP)	1.0	2.0	2.0				1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	1971 and Older Wrapped Steel (LP - IP)	1.0	2.0	2.0				1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	1972 and Newer Wrapped Steel (LP - IP)	1.0	2.0	2.0				1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	1985 and Older Polyethylene (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	1986 and Newer Polyethylene (LP - IP)	1.0	2.0	2.0	1.0	2.5	2.5	1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	Wrapped Steel (HP)	0.5	2.5	1.3				1.0	3.0	3.0	3.0	3.0	9.0	0.5	3.0	1.5	1.0	3.0	3.0	1.0	3.0	3.0	0.5	3.0	1.5	1.0	3.0	3.0
	Idle Riser	1.0	2.0	2.0	1.0	2.5	2.5	1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	Wrapped Steel in Casing							1.0	2.5	2.5	3.0	1.5	4.5	3.0	1.5	4.5	2.0	1.5	3.0	1.0	1.5	1.5	2.0	1.5	3.0	1.0	1.5	1.5
	Shallow	1.0	2.0	2.0	1.0	2.5	2.5	1.0	2.5	2.5	3.0	3.0	9.0	3.0	3.0	9.0	2.0	3.0	6.0	1.0	3.0	3.0	2.0	3.0	6.0	1.0	3.0	3.0
	Wall-to-Wall Paving/HOS	0.5	3.0	1.5	0.5	3.0	1.5	1.0	3.0	3.0	3.0	3.0	9.0	3.0	3.0	9.0	2.0	3.0	6.0	1.0	3.0	3.0	2.0	3.0	6.0	1.0	3.0	3.0
MSA	*MSA*																											
	Residential MSA							1.0	2.0	2.0																		
	Buried MSA							1.0	2.0	2.0																		
	Commercial and Industrial MSA							1.0	2.0	2.0																		
	Sidewalk and Street Vault Regulators							1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
	Aboveground Regulators							1.0	2.5	2.5																		
	MSA with Insufficient Traffic Protection							1.0	2.0	2.0																		
Valve	*Valves*																											
	Newer Valves (STW and PE)	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0
	Older Valves (STW)	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0
	Double IF Valves	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.0	2.0
FT	*Farm Tap*																											
	Single Service Farm Tap				0.5	2.5	1.3	1.0	3.0	3.0	3.0	3.0	9.0	1.5	3.0	4.5	1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0
	Modified Farm Tap (Farm Tap on Riser)				0.5	3.0	1.5	1.0	3.0	3.0																		
RS	*Regulator Stations*																											
	Gate Station, Town Border Station, Limiting Station				0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
	HP-IP District Regulator Station				0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
	IP-LP District Regulator Station				0.5	2.5	1.3	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
Pro	*Propane Peak-Shaving Plant and Distribution System*																											
	Propane Distribution System - Sumner	1.0	2.0	2.0	1.0	2.0	2.0	1.0	2.5	2.5	3.0	2.5	7.5	3.0	2.5	7.5	2.0	2.5	5.0	1.0	2.5	2.5	2.0	2.5	5.0	1.0	2.5	2.5
	Swarr Propane-Air Plant	0.5	1.0	0.5	0.5	1.0	0.5	1.0	2.0	2.0				0.5	1.0	0.5	0.5	1.0	0.5				0.5	1.0	0.5			

Effective Date: 08/02/2011
Cancelling Date: NEW

Distribution Integrity Management Program

Risk Evaluation and Prioritization Matrix

Frequency of Failure (FOF) or Pontential Failure:
0.5 - Occurs Almost Never
1.0 - Occurs Occasionally
1.5 - Occurs Sometimes
2.0 - Occurs Frequently
2.5 - Occurs More than Frequently
3.0 - Occurs Most Frequently

Consequence of Failure (COF) or Potential Consequence:
0.5 - Little or No Consequence
1.0 - Little to Moderate Consequence
1.5 - Moderate Consequence
2.0 - Moderate to High Consequence
2.5 - High Consequence
3.0 - Highest Consequence

Total Relative Score (TOT):
TOT = FOF x COF

Other Outside Force Damage

Asset	Vehicle Damage FOF	Vehicle Damage COF	Vehicle Damage TOT	Vandalism/Tampering/Unintentional Damage FOF	Vandalism/Tampering/Unintentional Damage COF	Vandalism/Tampering/Unintentional Damage TOT	Electrical Faults FOF	Electrical Faults COF	Electrical Faults TOT	Structure Fire FOF	Structure Fire COF	Structure Fire TOT
Main – *Main*												
Bare Steel (LP - IP)							1.0	2.0	2.0			
1971 and Older Wrapped Steel (LP - IP)							1.0	2.0	2.0			
1972 and Newer Wrapped Steel (LP - IP)							1.0	2.0	2.0			
1985 and Older Polyethylene (LP - IP)							1.0	2.0	2.0			
1986 and Newer Polyethylene (LP - IP)							1.0	2.0	2.0			
Wrapped Steel (HP)							1.0	2.5	2.5			
Wrapped Steel in Casing							1.0	2.0	2.0			
Shallow				0.5	2.5	1.3	1.0	2.0	2.0			
Wall-to-Wall Paving/HOS							1.0	3.0	3.0			
Service – *Service*												
Bare Steel (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
1971 and Older Wrapped Steel (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
1972 and Newer Wrapped Steel (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
1985 and Older Polyethylene (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
1986 and Newer Polyethylene (LP - IP)	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
Wrapped Steel (HP)	0.5	3.0	1.5	1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0
Idle Riser	1.0	2.5	2.5	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.0	2.0
Wrapped Steel in Casing	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
Shallow	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
Wall-to-Wall Paving/HOS	1.0	3.0	3.0	1.0	3.0	3.0	1.0	2.5	2.5	1.0	3.0	3.0
MSA – *MSA*												
Residential MSA	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0	1.0	2.0	2.0
Buried MSA	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0	1.0	2.0	2.0
Commercial and Industrial MSA	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0	1.0	2.0	2.0
Sidewalk and Street Vault Regulators	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
Aboveground Regulators	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.0	2.0
MSA with Insufficient Traffic Protection	1.5	3.0	4.5	1.0	2.5	2.5	1.0	2.0	2.0	1.0	2.0	2.0
Valve – *Valves*												
Newer Valves (STW and PE)							1.0	2.0	2.0			
Older Valves (STW)							1.0	2.0	2.0			
Double IF Valves							1.0	2.0	2.0			
FT – *Farm Tap*												
Single Service Farm Tap	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
Modified Farm Tap (Farm Tap on Riser)	1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0	1.0	3.0	3.0
RS – *Regulator Stations*												
Gate Station, Town Border Station, Limiting Station	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
HP-IP District Regulator Station	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
IP-LP District Regulator Station	1.0	3.0	3.0	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5
Pro – *Propane Peak-Shaving Plant and Distribution System*												
Propane Distribution System - Sumner	0.5	2.5	1.3	0.5	2.5	1.3	1.0	2.5	2.5	0.5	2.5	1.3
Swarr Propane-Air Plant	0.5	1.0	0.5	0.5	1.0	0.5	1.0	1.0	1.0	0.5	1.0	0.5

Material, Weld or Joint Failure

Asset	Brittle-like cracking failure FOF	Brittle-like cracking failure COF	Brittle-like cracking failure TOT	Fusion failure FOF	Fusion failure COF	Fusion failure TOT	Weld failure FOF	Weld failure COF	Weld failure TOT	Mechanical fitting failure FOF	Mechanical fitting failure COF	Mechanical fitting failure TOT
Main – *Main*												
Bare Steel (LP - IP)							2.0	1.5	3.0	1.0	2.0	2.0
1971 and Older Wrapped Steel (LP - IP)							2.0	1.5	3.0	1.0	2.0	2.0
1972 and Newer Wrapped Steel (LP - IP)							1.0	1.5	1.5	1.0	2.0	2.0
1985 and Older Polyethylene (LP - IP)	2.0	2.5	5.0	2.0	2.5	5.0				1.0	2.0	2.0
1986 and Newer Polyethylene (LP - IP)	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.0	1.0
Wrapped Steel (HP)							1.0	2.5	2.5			
Wrapped Steel in Casing							2.0	1.5	3.0	1.0	2.0	2.0
Shallow	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.0	1.0
Wall-to-Wall Paving/HOS	0.5	3.0	1.5	0.5	3.0	1.5				0.5	3.0	1.5
Service – *Service*												
Bare Steel (LP - IP)							2.0	2.0	4.0	1.0	2.5	2.5
1971 and Older Wrapped Steel (LP - IP)							2.0	2.0	4.0	1.0	2.5	2.5
1972 and Newer Wrapped Steel (LP - IP)							1.0	2.0	2.0	1.0	2.5	2.5
1985 and Older Polyethylene (LP - IP)	2.0	2.5	5.0	1.5	2.5	3.8				2.0	2.5	5.0
1986 and Newer Polyethylene (LP - IP)	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.5	1.3
Wrapped Steel (HP)							1.0	3.0	3.0			
Idle Riser	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.5	1.3
Wrapped Steel in Casing							1.5	2.0	3.0	1.0	2.5	2.5
Shallow	0.5	2.5	1.3	0.5	2.5	1.3				0.5	2.5	1.3
Wall-to-Wall Paving/HOS	0.5	3.0	1.5	0.5	3.0	1.5				0.5	3.0	1.5
MSA – *MSA*												
Residential MSA												
Buried MSA												
Commercial and Industrial MSA							1.0	2.0	2.0	1.0	2.0	2.0
Sidewalk and Street Vault Regulators							1.0	2.5	2.5	1.0	2.5	2.5
Aboveground Regulators							1.0	2.5	2.5			
MSA with Insufficient Traffic Protection							1.0	2.0	2.0	1.0	2.0	2.0
Valve – *Valves*												
Newer Valves (STW and PE)				1.0	3.0	3.0	1.0	2.0	2.0			
Older Valves (STW)				1.0	3.0	3.0	1.0	2.0	2.0			
Double IF Valves							1.0	2.0	2.0			
FT – *Farm Tap*												
Single Service Farm Tap							1.0	2.5	2.5			
Modified Farm Tap (Farm Tap on Riser)							1.0	3.0	3.0			
RS – *Regulator Stations*												
Gate Station, Town Border Station, Limiting Station							1.0	2.5	2.5			
HP-IP District Regulator Station							1.0	2.5	2.5			
IP-LP District Regulator Station							1.0	2.5	2.5			
Pro – *Propane Peak-Shaving Plant and Distribution System*												
Propane Distribution System - Sumner	1.0	2.5	2.5	1.0	2.5	2.5	1.0	2.5	2.5	0.5	2.0	1.0
Swarr Propane-Air Plant							1.0	2.0	2.0	0.5	1.0	0.5

Equipment Failure / Incorrect Operations / Other

Asset	Celcon Service Tee Caps FOF	Celcon Service Tee Caps COF	Celcon Service Tee Caps TOT	Valves FOF	Valves COF	Valves TOT	Regulator Failure FOF	Regulator Failure COF	Regulator Failure TOT	Operating Error FOF	Operating Error COF	Operating Error TOT	Sewer Cross Bore FOF	Sewer Cross Bore COF	Sewer Cross Bore TOT	Other FOF	Other COF	Other TOT
Main – *Main*																		
Bare Steel (LP - IP)										1.0	2.0	2.0	0.5	3.0	1.5	1.0	1.0	1.0
1971 and Older Wrapped Steel (LP - IP)										1.0	2.0	2.0	1.5	3.0	4.5	1.0	1.0	1.0
1972 and Newer Wrapped Steel (LP - IP)										1.0	2.0	2.0	1.5	3.0	4.5	1.0	1.0	1.0
1985 and Older Polyethylene (LP - IP)										1.0	2.0	2.0	1.5	3.0	4.5	1.0	1.0	1.0
1986 and Newer Polyethylene (LP - IP)										0.5	2.0	1.0	1.5	3.0	4.5	1.0	1.0	1.0
Wrapped Steel (HP)										1.0	2.5	2.5	0.5	3.0	1.5	1.0	1.0	1.0
Wrapped Steel in Casing										1.0	2.0	2.0				1.0	1.0	1.0
Shallow										0.5	2.0	1.0	1.5	3.0	4.5	1.0	1.0	1.0
Wall-to-Wall Paving/HOS										0.5	3.0	1.5	1.5	3.0	4.5	1.0	3.0	3.0
Service – *Service*																		
Bare Steel (LP - IP)										1.0	2.5	2.5	0.5	3.0	1.5	1.0	1.0	1.0
1971 and Older Wrapped Steel (LP - IP)										1.0	2.5	2.5	1.5	3.0	4.5	1.0	1.0	1.0
1972 and Newer Wrapped Steel (LP - IP)										1.0	2.5	2.5	1.5	3.0	4.5	1.0	1.0	1.0
1985 and Older Polyethylene (LP - IP)	1.0	2.5	2.5							1.0	2.5	2.5	1.5	3.0	4.5	1.0	1.0	1.0
1986 and Newer Polyethylene (LP - IP)	1.0	2.5	2.5							0.5	2.5	1.3	1.5	3.0	4.5	1.0	1.0	1.0
Wrapped Steel (HP)										0.5	3.0	1.5	0.5	3.0	1.5	1.0	1.0	1.0
Idle Riser	1.0	2.5	2.5							0.5	2.5	1.3	1.5	3.0	4.5	1.0	1.0	1.0
Wrapped Steel in Casing										1.0	2.5	2.5				1.0	1.0	1.0
Shallow	1.0	2.5	2.5							0.5	2.5	1.3	1.5	3.0	4.5	1.0	1.0	1.0
Wall-to-Wall Paving/HOS	1.0	3.0	3.0							0.5	3.0	1.5	1.5	3.0	4.5	1.0	3.0	3.0
MSA – *MSA*																		
Residential MSA							1.0	2.0	2.0	1.0	1.0	1.0				1.0	1.0	1.0
Buried MSA							1.0	2.0	2.0	1.0	1.0	1.0				1.0	1.0	1.0
Commercial and Industrial MSA							1.0	2.0	2.0	1.0	1.0	1.0				1.0	1.0	1.0
Sidewalk and Street Vault Regulators							1.5	2.0	3.0	1.0	1.0	1.0				1.0	1.0	1.0
Aboveground Regulators							1.0	2.0	2.0	1.0	1.0	1.0				1.0	1.0	1.0
MSA with Insufficient Traffic Protection							1.0	2.0	2.0	1.0	1.0	1.0				1.0	1.0	1.0
Valve – *Valves*																		
Newer Valves (STW and PE)				1.0	2.0	2.0				1.0	1.0	1.0				1.0	1.0	1.0
Older Valves (STW)				2.0	2.0	4.0				1.0	1.0	1.0				1.0	1.0	1.0
Double IF Valves				2.0	2.0	4.0				1.0	1.0	1.0				1.0	1.0	1.0
FT – *Farm Tap*																		
Single Service Farm Tap							1.0	2.5	2.5	1.0	2.5	2.5				1.0	1.0	1.0
Modified Farm Tap (Farm Tap on Riser)							1.0	3.0	3.0	1.0	3.0	3.0				1.0	1.0	1.0
RS – *Regulator Stations*																		
Gate Station, Town Border Station, Limiting Station							1.0	2.5	2.5	1.0	2.5	2.5				1.0	1.0	1.0
HP-IP District Regulator Station							1.0	2.5	2.5	1.0	2.5	2.5				1.0	1.0	1.0
IP-LP District Regulator Station							1.0	2.5	2.5	1.0	2.5	2.5				1.0	1.0	1.0
Pro – *Propane Peak-Shaving Plant and Distribution System*																		
Propane Distribution System - Sumner	1.0	2.5	2.5	1.0	2.0	2.5	1.0	2.5	2.5	1.0	2.5	2.5	1.5	3.0	4.5	0.5	1.0	0.5
Swarr Propane-Air Plant				1.0	1.0	1.0	1.0	1.0	1.0	0.5	1.0	0.5				0.5	1.0	0.5

Scores and Priorities

Asset	Total Risk Score	Risk Score from Excavation Damage	Risk Score from Sewer Crossbore	Adjusted Risk Score	% of Risk Score from Excavation Damage	Ranking	Risk Priority based on Combination of Threats (excludes Excavation Damage and Sewer Cross Bores)	Risk Priority based on Specific Threats (excludes Excavation Damage and Sewer Cross Bores)	Risk Priority based on Excavation Damage Only	Risk Priority based on Sewer Cross Bore Only	Meets Requirement for Additional and Accelerated Actio
Main – *Main*							22.8	4.0	4.0	4.0	
Bare Steel (LP - IP)	51	24	2	25.0	48%	3	1	N/A	1	2	Y
1971 and Older Wrapped Steel (LP - IP)	52	24	5	23.5	46%	4	1	N/A	1	1	Y
1972 and Newer Wrapped Steel (LP - IP)	49	24	5	20.5	49%	7	2	2	1	1	Y
1985 and Older Polyethylene (LP - IP)	56	24	5	27.8	43%	1	1	N/A	1	1	Y
1986 and Newer Polyethylene (LP - IP)	46	24	5	17.8	52%	9	2	2	1	1	Y
Wrapped Steel (HP)	41	16.25	2	23.0	40%	5	1	N/A	1	2	Y
Wrapped Steel in Casing	34	12	0	22.0	35%	6	2	2	2	2	N
Shallow	54	30	5	19.0	56%	8	2	2	1	1	Y
Wall-to-Wall Paving/HOS	67	36	5	26.5	54%	2	1	N/A	1	1	Y
Service – *Service*							36.1	4.0	4.0	4.0	
Bare Steel (LP - IP)	72	30	2	40.0	42%	2	1	N/A	1	2	Y
1971 and Older Wrapped Steel (LP - IP)	73	30	5	38.0	41%	3	1	N/A	1	1	Y
1972 and Newer Wrapped Steel (LP - IP)	69	30	5	34.0	44%	6	2	2	1	1	Y
1985 and Older Polyethylene (LP - IP)	78	30	5	43.8	38%	1	1	N/A	1	1	Y
1986 and Newer Polyethylene (LP - IP)	66	30	5	31.5	45%	9	2	2	1	1	Y
Wrapped Steel (HP)	59	21	2	36.8	35%	5	1	N/A	1	2	Y
Idle Riser	68	30	5	33.0	44%	8	2	2	1	1	Y
Wrapped Steel in Casing	52	18	0	34.0	35%	6	2	2	1	2	Y
Shallow	72	36	5	31.5	50%	9	2	2	1	1	Y
Wall-to-Wall Paving/HOS	79	36	5	38.0	46%	3	1	N/A	1	1	Y
MSA – *MSA*							34.8	4.0	4.0	4.0	
Residential MSA	26	0	0	26.0	0%	6	2	2	2	2	N
Buried MSA	36	0	0	35.5	0%	3	1	N/A	2	2	Y
Commercial and Industrial MSA	31	0	0	30.5	0%	5	2	2	2	2	N
Sidewalk and Street Vault Regulators	59	15	0	44.3	25%	1	1	N/A	2	2	Y
Aboveground Regulators	40	0	0	39.8	0%	2	1	N/A	2	2	Y
MSA with Insufficient Traffic Protection	33	0	0	32.5	0%	4	2	1	2	2	Y
Valve – *Valves*							30.0	4.0	4.0	4.0	
Newer Valves (STW and PE)	41	12	0	29.0	29%	3	2	2	2	2	N
Older Valves (STW)	43	12	0	31.0	28%	1	1	N/A	2	2	Y
Double IF Valves	42	12	0	30.0	29%	2	2	1	2	2	Y
FT – *Farm Tap*							42.0	4.0	4.0	4.0	
Single Service Farm Tap	66	25.5	0	40.0	39%	2	2	2	1	2	Y
Modified Farm Tap (Farm Tap on Riser)	44	0	0	44.0	0%	1	1	N/A	2	2	Y
RS – *Regulator Stations*							42.1	4.0	4.0	4.0	
Gate Station, Town Border Station, Limiting Station	60	15	0	44.8	25%	1	1	N/A	2	2	Y
HP-IP District Regulator Station	56	15	0	40.8	27%	2	2	2	2	2	N
IP-LP District Regulator Station	56	15	0	40.8	27%	2	2	2	2	2	N
Pro – *Propane Peak-Shaving Plant and Distribution System*							32.5	4.0	4.0	4.0	
Propane Distribution System - Sumner	81	30	5	46.5	37%	1	1	N/A	1	1	Y
Swarr Propane-Air Plant	20	1.5	0	18.5	8%	2	2	2	2	2	N

Effective Date: 08/02/2011
Cancelling Date: NEW

	Facilities Requiring Additional and Accelerated Actions Based on a Combination of Threats or Specific Threats (Excludes Excavation Damage and Sewer Cross Bores)
Main	
Bare Steel (LP - IP)	🟩
1971 and Older Wrapped Steel (LP - IP)	🟩
1972 and Newer Wrapped Steel (LP - IP)	✓
1985 and Older Polyethylene (LP - IP)	🟩
1986 and Newer Polyethylene (LP - IP)	✓
Wrapped Steel (HP)	🟨
Wrapped Steel Main in Casing	✓
Shallow Main	✓
Main in Wall-to-Wall Paving/HOS	🟨
Service	
Bare Steel (LP - IP)	🟩
1971 and Older Wrapped Steel (LP - IP)	🟩
1972 and Newer Wrapped Steel (LP - IP)	✓
1985 and Older Polyethylene (LP - IP)	🟩
1986 and Newer Polyethylene (LP - IP)	✓
Wrapped Steel (HP)	🟨
Service with Idle Riser	✓
Wrapped Steel Service in Casing	✓
Shallow Service	✓
Service in Wall-to-Wall Paving/HOS	🟨
MSA	
Residential MSA	✓
Buried MSA	🟨
Commercial and Industrial MSA	✓
Sidewalk and Street Vault Regulators	🟩
Aboveground Regulators	🟩
MSA with Insufficient Traffic Protection	🟨 X Vehicle Damage
Valves	
Newer Valves (STW and PE)	✓
Older Valves (STW)	🟨
Double Insulated Flanged Valves	🟨 X Corrosion and Valves
Farm Tap	
Single Service Farm Tap	✓
Modified Farm Tap (Farm Tap on Riser)	🟨
Regulator Stations	
Gate Station, Town Border Station, Limiting Station	🟨
HP-IP District Regulator Station	✓
IP-LP District Regulator Station	✓
Propane Peak-Shaving Plant and Distribution System	
Propane Distribution System - Sumner	🟨
Swarr Propane-Air Plant	✓

Threats (Sub-Threat)	**Threats Requiring Additional and Accelerated Actions System-Wide**
Corrosion	✓
Natural Forces	✓
Excavation Damage	🟨
Other Outside Force Damage	✓
Material, Weld or Joint Failure	✓
Equipment Failure	✓
Incorrect Operations (Sewer Cross Bores)	🟥
Other	✓

Legend

Additional and accelerated actions are not required.

✓ **Existing mitigative measures are adequate.**

Additional and accelerated actions are required.

🟩 **Existing mitigative measures are adequately reducing risks and additional and accelerated actions have been implemented to reduce risk.**

🟨 **Existing mitigative measures have been implemented, but additional and accelerated actions need to be developed to further reduce risk.**

🟥 **Existing mitigative measures are inadequate and/or no additional and accelerated actions are currently implemented, but are in development to reduce risks.**

X **Additional and accelerated actions are required only for the specific threats as listed.**

Effective Date: 08/02/2011
Cancelling Date: NEW

Appendix D: Summary of Mitigative Measures

Table D-1: Summary of Mitigative Measures

Mitigative Measures	Reference to Supporting Documentation	THREAT							
		Corrosion	Natural Forces	Excavation Damage	Other Outside Force Damage	Material, Weld or Joint Failure	Equipment Failure	Incorrect Operations	Other
Leak Management Program	GOS 2425.1400 Investigating Emergency Calls and Reports GOS 2450.1600 Instrument Calibration GOS 2475.1100 Prioritizing Service Orders GOS 2575.1900 Investigating Failures of Pipeline Facilities GOS 2625.1100 Leakage Survey Program* GOS 2625.1200 Conducting Leakage Surveys GOS 2625.1300 Leakage Action Program GOS 2675.1200 Propane Leakage Program Quality Assurance Program Plan	✓	✓	✓	✓	✓	✓	✓	✓
Odorization	GOS 2450.1600 Instrument Calibration GOS 2650.1000 Odorization Requirements and Odor Level Testing GOS 2650.1100 Odorizing Station Design GOS 2650.1200 Odorizing Station Inspection and Adjustment GOS 2650.1300 Storing and Handling Odorant and Filling Odorizers	✓	✓	✓	✓	✓	✓	✓	✓

Mitigative Measures	Reference to Supporting Documentation	THREAT							
		Corrosion	Natural Forces	Excavation Damage	Other Outside Force Damage	Material, Weld or Joint Failure	Equipment Failure	Incorrect Operations	Other
Public Awareness Program	GOS 2425.1500 Public Awareness Program Public Awareness Program Plan	✓	✓	✓	✓	✓	✓	✓	✓
Design and Construction Practices	Gas Operating Standards Gas Field Procedures Design and Construction Manual	✓	✓	✓	✓	✓	✓	✓	✓
Increase leak survey frequency	DIM Plan Appendix F-1 – Wrapped Steel Service Assessment Program	✓	✓	✓	✓	✓	✓	✓	✓
Replacement and Mitigation Programs • Bare Steel • WSSAP • Wrapped Steel Pipe • Older Vintage PE Pipe	Bare Steel Settlement Agreement DIM Plan Appendix F – Risk Mitigation Programs	✓	✓	✓	✓	✓	✓	✓	✓
Monitor trends and system performance and identify appropriate additional/accelerated actions	GOS 2475.2700 Continuing Surveillance	✓	✓	✓	✓	✓	✓	✓	✓
Operations and Maintenance Practices (e.g. valves, regulator stations, pipeline markers)	Gas Operating Standards	✓	✓	✓	✓		✓	✓	
Continuing Surveillance Program	GOS 2475.2700 Continuing Surveillance GOS 2575.3100 Patrolling Program	✓	✓	✓	✓	✓			
Patrolling	GOS 2575.3100 Patrolling Program		✓	✓	✓				
Installation of excess flow valves	GOS 2550.1600 Service Components GOS 2550.2200 Excess Flow Valves		✓	✓	✓				

Mitigative Measures	Reference to Supporting Documentation	THREAT							
		Corrosion	Natural Forces	Excavation Damage	Other Outside Force Damage	Material, Weld or Joint Failure	Equipment Failure	Incorrect Operations	Other
Corrosion Control	GOS 2600.1000 Cathodic Protection Requirements GOS 2600.1100 Coatings for Pipe and Fittings GOS 2600.1200 Test Station Requirements GOS 2600.1300 Designing and Installing Cathodic Protection Systems GOS 2600.1400 Electrical Isolation and Grounding Requirements GOS 2600.1500 Monitoring Cathodic Protection GOS 2600.1600 Unprotected Facilities GOS 2600.1700 Monitoring and Remedial Measures for Internal Corrosion GOS 2600.1800 Monitoring Facilities for Atmospheric Corrosion GOS 2600.1900 Remedial Measures for Corrosion Control GOS 2600.2000 Galvanic Anode Installation Requirements	✓							
Emergency Response Plan	Gas Operating Standards PSE Corporate Emergency Response Plan Emergency Action Plans for Gig Harbor Emergency Action Plans for Swarr		✓						
Damage Prevention Program	GOS 2425.1600 Damage Prevention Program Damage Prevention Program Plan			✓					
Operator Qualification Program	GOS 2425.2100 Operator Qualification Operator Qualification Plan							✓	

Mitigative Measures	Reference to Supporting Documentation	THREAT							
		Corrosion	Natural Forces	Excavation Damage	Other Outside Force Damage	Material, Weld or Joint Failure	Equipment Failure	Incorrect Operations	Other
Gas Maintenance Programs • Isolated Facilities Program • Regulator Station Remediation • Converted Single Service Farm Tap Program • Regulator Pipe Support Mitigation • Regulator Station Over Pressure Protection • Industrial Meter Set Remediation • Buried MSA Remediation • Traffic Protection Enhancements • Rock and Debris on Buried Pipe • Shallow Main and Service Remediation • Mobile Home Community (MHC) Encroachment Surveys • Bridge and Slide Remediation • Atmospheric Corrosion at Hard-to-Reach Bridges • Aging High-Pressure Valve Mitigation • Double Insulated Flange Valve Mitigation • High Voltage Alternating Current (HVAC) Mitigation Program • Transmission Integrity Management Program	Continuing Surveillance Annual Report	✓	✓	✓	✓	✓	✓	✓	✓

Appendix E: Additional and Accelerated Actions

Table E-1: Summary of Additional and Accelerated Actions[1]

Reference	Topic	Requirement
GOS 2525.1100 Pipeline Design	Design Factor	This specifies that a design factor of 0.2 shall be used for all piping with the exception of the inlet to gate stations.
GOS 2525.3300 Test Requirements	Test Factor	This requires that all steel pipelines operating above 100 psig be tested to 1.5 times the proposed pipeline MAOP.
GOS 2525.1100 Welder Qualification Requirements	Welding	Requires Arc welding on all pipelines operating above 60 psig except pipe 1 ½" or less in diameter.
GOS 2425.1600 Damage Prevention Program	Construction Monitoring	For excavations in the vicinity of mains operating above 60 psig, anode beds, rectifier stations, or pressure regulating stations, this requires PSE contact the excavator to confirm excavation details. Requires excavations in the vicinity of mains operating above 60 psig to be monitored as frequently as necessary during and after excavation activities to verify the integrity of the pipeline and for the inspector to be onsite when excavation begins.
GOS 2625.1100 Leakage Survey Program	Survey frequency	Mains operating at or above 250 psig are leak surveyed annually. Mains operating above 60 psig and below 250 psig are leak surveyed every three years not to exceed 39 months.
Company Practice	Leak survey	All mains are surveyed at least every three years not to exceed 39 months.
Subject Matter Experts	Weld inspection	Close to 100% inspection of all welds on pipelines operating above 60 psig.
GOS 2525.1700 Excavation, Underground Clearance, Cover, and Restoration	Cover	Most mains are installed 30 inches and most services are installed at least 18 inches deep.
Bare Steel Settlement Agreement DIM Plan Appendix F	Replacement and Risk Mitigation Programs	Risk rank and replace or perform increased leak survey on higher ranking facilities including bare steel, wrapped steel services, older wrapped steel pipe, older PE pipe.

[1] This summary is not comprehensive and will continue to be updated.

Appendix F: Risk Mitigation Programs

Appendix F-1: Wrapped Steel Service Assessment Program (WSSAP)

1. Scope

This document defines the methodology to be applied for the risk assessment and determination of appropriate mitigative measure for pre-1972 wrapped steel services. This program includes services installed between 1956 and 1972. Services installed prior to 1956 are assumed to be bare steel services and will be replaced under the Bare Steel Replacement program.

2. Responsibilities

2.1 The *Manager of Gas System Integrity* shall be responsible for:

2.1.1 Overall program management including:

2.1.1.1 Ensuring the risk model is run annually and validated as described in Section 4.

2.1.1.2 Ensuring a quality assurance plan is developed and implemented.

2.1.1.3 Ensuring any modifications to the risk model, mitigation actions, or mitigation category thresholds are approved as required in Section 4.4 and 7.3.

2.1.1.4 Ensuring any approved modifications are documented in a format similar to the WSSAP final report.

2.1.2 Creating work orders for service replacements in accordance with Section 6.1.

2.1.3 Monitoring completion of the work orders.

2.3 The *Manager Contract Management* shall be responsible for ensuring that work orders for replacements are completed in accordance with this program plan and as specified on the work order.

2.4 The *Manager System Control and Protection* shall be responsible for ensuring leakage surveys are carried out in accordance with this program plan.

2.5 The *Manager Compliance and Regulatory Audits* shall be responsible for obtaining WUTC approval for any changes to the program including modifications to the risk model, mitigation actions, or mitigation category thresholds as required in Section 4.4 and 7.3.

2.5 The *Manager Data and Applications Services* shall be responsible for supporting the WSSAP risk model including importing data from SAP, LMS, and other applicable data sources as necessary to rerun the risk model and provide status updates.

2.6 The *Manager Maps and Records* shall be responsible for:

2.6.1 Updating service records in the WSSAP database as new service records are processed.

2.6.2 Researching and updating service records in the WSSAP database as additional review is performed of existing data.

2.6.3 Performing service record review (D-4) as necessary prior to replacement of WSSAP services.

3. General

3.1 The wrapped steel service mitigation program uses a risk model to categorize services into four mitigation categories. These categories specify what mitigation is required as detailed in section 6, Table 1 of this program plan.

3.2 The four mitigation categories are Priority Replacement, Scheduled Replacement, Increased Leak Survey, and Standard Mitigation.

4. WSSAP Risk Model

4.1 The risk model calculates a risk score for each service based upon multiple variables. A summary of the variables and the functionality of the risk model are provided in the Wrapped Steel Service Assessment Program Final Report Revision 4.0, dated October 6, 2006 (WSSAP Final Report).

4.2 The risk model shall continue to be populated with new and additional data.

4.3 The risk model shall be run annually to provide a new risk assessment of all pre-1972 wrapped steel services.

4.4 PSE shall consult with WUTC Staff and obtain agreement on any revisions to the risk model and/or mitigation action thresholds.

5. Service Mitigation Categories

5.1 In accordance with the methodology outlined in the WSSAP Final Report, the mitigation categories shall be determined based on the following criteria, i.e. mitigation category thresholds:

5.2.1 Priority Replacement - Services with probability of failure (POF) scores ≥ 56% or a report of coating disbondment.

5.2.2 Scheduled Replacement - Services with POF scores ≥ 41% and < 56% and no cathodic protection (no cp alert).

5.2.3 Increased Leak Survey – The top 25% of all services with a POF score <41%.

5.2.4 Standard Mitigation - Services that are not in the first three categories.

6. Mitigation Plan

6.1 Services shall be mitigated based on their mitigation category as described in Table 1.

Table 1. Mitigation Plan

Mitigation Category	Mitigation Plan Description
Priority Replacement	• Replace in the calendar year following when they are identified as a priority replacement except where customer issues, permits, or other unusual circumstances prevent replacement. • Leak survey service twice per calendar year until replaced. Leak surveys shall be at a frequency not less than 4 months and not greater than 8 months.
Scheduled Replacement	• Schedule for replacement within 4 calendar years of being identified as a scheduled replacement except where customer issues, permits, or other unusual circumstances prevent replacement. • Leak survey service twice per calendar year until replaced. Leak surveys shall be at a frequency not less than 4 months and not greater than 8 months.
Increased Leak Survey	• Leak survey annually not to exceed 15 months.
Standard Mitigation	• Perform normal operation and maintenance activities.

6.2 Prior to replacement, adjacent services and mains shall be evaluated to determine whether additional facilities in the vicinity should be replaced.

6.2.1 If several services in an area have been replaced due to similar indications, adjacent services of similar vintage or subject to the same threats shall also be replaced.

6.2.2 Adjacent mains shall be investigated for evidence of corrosion. This may include review of construction, O&M records, performing electrical surveys, or excavating and performing direct examination.

7. Measure Performance, Monitor Results, and Evaluate Effectiveness

7.1 PSE will measure the performance of WSSAP services in each mitigation category to evaluate opportunities to refine the WSSAP risk model. This shall include tracking the following information and evaluating the trends:

7.1.1 The number of leaks discovered each year by mitigation category including both active leaks and repaired leaks by leak cause.

7.1.2 The percent of services with a leak discovered in each mitigation category.

7.1.3 The number of services mitigated during the previous calendar year by mitigation category. If any priority services where not mitigated, PSE shall track these services and ensure they are mitigated in a timely manner.

7.1.4 The number of services targeted for replacement for the current calendar year.

7.2 The data required by 7/1 shall be reported in the Continuing Surveillance Annual Report and shall include a discussion of the trends and the evaluation of the effectiveness of the WSSAP risk model.

7.2.1 If any annual status report indicates the number of leaks in the standard mitigation category exceed 2.76% of the services, the model shall be recalibrated to more accurately reflect the risk of failure of services within such category.

7.3 If revisions to the WSSAP risk model are required, a plan for how PSE will proceed with making the revisions shall also be included in the Continuing Surveillance Annual Report. This plan shall include the process for obtaining WUTC Staff's approval of any revisions to the WSSAP risk model.

8. Quality Assurance

8.1 PSE shall develop and implement a quality assurance program for each component of this program.

9. Records

9.1 Records summarizing the results of each annual risk assessment shall be maintained for 10 years.

Appendix F-2: Wrapped Steel Pipe Mitigation Program

1. Scope

This document defines the methodology to be applied for the risk assessment and determination of appropriate mitigative measures for wrapped steel pipelines. This mitigation plan applies to wrapped steel pipelines of all installation years and intermediate pressure and below.

2. Responsibilities

2.2 The *Manager Gas System Integrity* shall be responsible for:

2.2.1 Overall program management including:

2.2.1.1 Ensuring the risk model is run annually and validated as described in Section 4.

2.2.1.2 Ensuring any modifications to the risk model, mitigation actions or mitigation category thresholds are documented as required in Section 7.

2.2.2 Creating work orders for main and service replacements in accordance with Section 6.1.

2.2.3 Monitoring completion of the work orders.

2.3 The *Manager Contract Management* shall be responsible for ensuring that work orders for replacements are completed in accordance with this program plan and as specified on the work order.

3. General

3.2. Wrapped steel pipeline segments are prioritized when identified where there are more than 3 active leaks or a combination of more than 4 active or repaired leaks or pipe condition concerns within 500’ of main.

3.2 These segments are identified through plat reviews, field personnel, and normal work activities.

3.3 The wrapped steel pipeline mitigation plan uses a risk model to categorize pipeline segments into five mitigation categories. These categories specify what mitigation is required as detailed in Section 6 Table 1 of this plan.

3.3.1 The four mitigation categories are Scheduled Replacement, Phased Program Replacement, Suitable for Monitoring, and Standard Mitigation.

3.4 Segments are prioritized accordingly when replacement work coincides with other planned work under different programs and if replacement of segment mitigates multiple risks.

4. Prioritizing Pipeline Replacements

4.1. A comprehensive risk model shall be used to perform a system risk assessment in order to prioritize replacement segments. The first comprehensive risk ranking of identified wrapped steel pipeline segments was performed in 2010.

4.1.1. The risk model calculates the risk score based upon the following factors:

4.1.1.1. Leak history – active and repaired leaks;

4.1.1.1.1. Leak grade;

4.1.1.1.2. Leak cause;

4.1.1.1.3. Leak frequency;

4.1.1.2. Condition of pipe from exposed pipe condition reports; and,

4.1.1.3. Proximity to high occupancy structures (HOS).

4.1.2. The risk factors are assigned a relative weighting in accordance with Table 1.

4.1.3. Each segment has two risk scores which are calculated by the concerned main footage and the proposed main footage. The concerned main footage is the footage in which the concerns are limited to and proposed main footage is the footage in which is most practical to replace.

4.1.4. The risk scores are determined using the Relative Weighting value, number of occurrences of an event, and main footage in accordance with the following formula:

([Relative Weighting] x [# of occurrences]) ÷ [Concerned Main footage] = [Concerned Risk Score]

([Relative Weighting] x [# of occurrences]) ÷ [Proposed Main footage] = [Proposed Risk Score]

4.2. A system risk assessment utilizing the risk model shall be performed each calendar year.

4.3. The risk model shall be validated based on Subject Matter Expert (SME) input and data.

4.4. Prioritization of replacement and mitigation footage may be adjusted based upon the following three categories:

4.4.1. Public Improvement

4.4.1.1. Coincident public improvement projects;

4.4.1.2. Right-of-way use restrictions or paving cut moratoriums;

4.4.2. Field Identified

4.4.3. Coordination with other Gas System Integrity replacement projects or coordination with replacing segments with the least impact to the cathodic protection system.

4.5. The risk model shall be updated annually to incorporate new data and newly identified segments.

Table 1. Wrapped Steel Pipeline Replacement Risk Ranking Matrix

FACTOR		CONSEQUENCE	RELATIVE WEIGHTING
Active Leak	Grade B1	HOS	0.13266
		NO HOS	0.06633
	Grade B2	HOS	0.02316
		NO HOS	0.01158
	Grade C	HOS	0.00434
		NO HOS	0.00217
	Grade 0	HOS	0.00064
		NO HOS	0.00032
Historic Leak	Grade A,BA	HOS	0.05668*
		NO HOS	0.02834*
	Grade B1	HOS	0.02720*
		NO HOS	0.01360*
	Grade B2	HOS	0.01176*
		NO HOS	0.00588*
	Grade C	HOS	0.00388*
		NO HOS	0.00194*
EPCR Condition	Deep/Frequent (General Corrosion, Multiple Pits Requiring Remediation)	HOS	0.03588
		NO HOS	0.01794
	Deep/Isolated (Isolated Pit Requiring Remediation)	HOS	0.00230
		NO HOS	0.00115
	Shallow/Frequent (Multiple Pit Not Requiring Remediation)	HOS	0.00122
		NO HOS	0.00061
	Shallow/Isolated (Isolated Pit Not Requiring Remediation)	HOS	0.00016
		NO HOS	0.00008
	Disbonded Coating	HOS	0.00696
		NO HOS	0.00348

4.5 Relative weightings with asterisks are maximum weightings for that specific factor. The relative weightings vary depending the following criteria:

4.5.1 Leak cause of historic leak;

4.5.2 No leak information, but leak repair is platted on plat map; or

4.5.3 Leak repair resulting in a main replacement.

4.6 The following table, Table 2, shows how each leak repair criteria is relatively scored (leak cause code is listed in parenthesis when applicable).

Table 2. Risk Factor Relative Weighting

Leak Repair Criteria	**Factor x Relative Weighting**
Leak Cause - Corrosion (A, J, K, L, M)	1.00
Leak Cause - Excavation Damage (B)	0.75
Leak Cause - Natural Forces (C)	0.75
Leak Cause - Operations (D)	0.75
Leak Cause - Material or Welds (E)	1.00
Leak Cause - Other (F)	1.00
Leak Cause - Equipment (G)	0.75
Leak Cause - Other Outside Force Damage (H)	0.75
Leak Cause - Non-exposed (I)	1.00
Platted Leak Clamps and Reinforcing Sleeves	1.00
Main Replacement (A, F, J, K, L, M)	2.00

4.7 The following table, Table 3, shows how each leak repair or indication is relatively scored based on the facility type:

4.7.1 An existing service is defined by the original service as currently still existing and was not completely replaced at the time of the leak repair.

4.7.2 A repaired service is defined by the original service as being completely replaced from meter to main at the time of the leak repair.

Table 3. Facility Risk Factor Relative Weighting

Facility	**Factor x Relative Weighting**
Main	1.00
Existing Service	1.00
Repaired Service	1.00

5. Wrapped Steel Pipeline Mitigation Categories

5.1 The mitigation categories shall be determined based on the following criteria except where SME review determines an alternate mitigation category is appropriate. Where SME's determine an alternate mitigation category is appropriate, the basis for this determination shall be documented for future reference. The following are the mitigation categories and the mitigation thresholds that prompt specific action to be taken:

5.1.1 Scheduled Replacement – Pipeline segments with a concerned score of ≥ 1.00 are considered for scheduled replacement and requires SME review when the concerned main footage is < 500', disbonded coating accounts for 50% or more of risk score, proposed risk score is < 0.80, services account for 50% or more of risk score or other concerns are present.

5.1.2 Phased Program Replacement – Pipeline segments that meet the requirements of scheduled replacement, but require a large scale replacement to be completed over a number of years.

5.1.3 Suitable for Monitoring – Pipeline segments that are not in the first three categories, but based on SME review should be monitored on an annual basis.

5.1.4 Standard Mitigation - Pipeline segments that are not in the other categories and require no action other than normal operation and maintenance activities.

5.2 The mitigation categories and mitigation category thresholds may change as specified in Section 7.

6. Mitigation Plan

6.1 Wrapped steel pipelines shall be mitigated based on their mitigation category as described in Table 4.

6.2 The mitigation actions may change as specified in Section 7.

Table 4. Mitigation Plan

Mitigation Category	Mitigation Plan Description
Scheduled Replacement	• Replace segment within 4 calendar years after identified as Scheduled Replacement except where customer issues, permits or other unusual circumstances prevent replacement, or unless additional data indicates the segment should be re-evaluated.
Phased Program Replacement	• Develop a phased plan to replace the larger segment considering the data. Document the plan and replace in accordance with the plan.
Suitable for Monitoring	• Re-evaluate segment on annual basis. Perform normal operation and maintenance activities.
Standard Mitigation	• Perform normal operation and maintenance activities.

7. Measure Performance, Monitor Results, and Evaluate Effectiveness

7.1 PSE will measure the performance of wrapped steel pipeline in each mitigation category to evaluate opportunities to refine the wrapped steel pipeline risk model. This shall include tracking the following information and evaluating the trends:

7.1.1 The number of corrosion leaks on wrapped steel mains and services each year.

7.1.3 The footage of wrapped steel pipelines replaced during the previous calendar year and wrapped steel pipelines not replaced on-time.

7.1.4 The footage of wrapped steel pipelines targeted for replacement for the current calendar year.

7.2 This data shall be reported in the Continuing Surveillance Annual Report and shall include a discussion of the trends and evaluation of the effectiveness of the wrapped steel pipeline risk model.

7.3 If revisions to the wrapped steel pipeline risk model and/or mitigation thresholds and actions are required, a plan for how PSE will proceed with making the revisions shall be included in the Continuing Surveillance Annual Report.

8. Records

8.1 Records summarizing the results of each annual risk assessment shall be maintained and incorporated into the distribution integrity management program.

8.2 Records demonstrating mitigation plans were implemented as required by this Plan shall be maintained.

Appendix F-3: Older Vintage PE Pipe Mitigation Program

1. Scope

This document defines the methodology to be applied for the risk assessment and determination of appropriate mitigative measure for older polyethylene (PE) mains and services. This program includes PE mains and services installed prior to 1986.

2. Responsibilities

2.1 The *Manager of Gas System Integrity* shall be responsible for:

2.1.1 Overall program management including:

2.1.1.1 Ensuring the risk model is run annually and validated as described in Section 4.

2.1.1.2 Ensuring any modifications are documented.

2.1.2 Creating work orders for main and service replacements in accordance with Section 6.1.

2.1.3 Monitoring completion of the work orders.

2.2 The *Manager Contract Management* shall be responsible for ensuring that work orders for replacements are completed as specified on the work order.

3. General

3.1 Older PE pipeline segments are risk ranked when one or more instances of brittle cracking or fusion failure are found on Aldyl HD pipe.

3.2.1 Segments are defined as concurrently installed facilities. For main this includes all main installed on the same job number. For services it includes the entire service or portion of service installed with the portion found defective.

3.2.2 The segment boundaries may be adjusted if appropriate based on subject matter expert knowledge to achieve the greatest reduction in overall system risk.

3.2 These locations are identified through material failure analysis, leak management system records and field personnel.

3.3 The older PE pipeline mitigation plan uses a risk model to categorize pipeline segments into four mitigation categories. These categories specify what mitigation is required as detailed in Section 6 of this plan.

3.2.1 The mitigation categories are Priority Replacement, Scheduled Replacement, Phased Program Replacement, and Suitable for Monitoring.

4. Prioritizing Pipeline Replacements

4.1. A comprehensive risk model shall be used to perform a system risk assessment in order to determine appropriate mitigation for pipe segments.

4.1.1. The risk model calculates the risk score based upon the following factors:

4.1.1.1. The likelihood of Leak frequency – the number of leaks caused by brittle cracking or fusion failure in conjunction with the vintage of the leak;

4.1.1.1.1. Leak severity – the leak grade;

4.1.1.1.2. Leak cause confidence – the confidence level that a leak was caused by brittle cracking or fusion failure;

4.1.1.1.3. The reported condition of pipe bedding from Form 3704; and,

4.1.1.1.4. Proximity to high occupancy structures (HOS).

4.1.2. The risk factors are assigned a relative weighting in accordance with Table 1.

4.1.3. The risk scores are determined using the Relative Weighting value, number of occurrences of each event, and main footage in accordance with the following formula:

([Relative Weighting] x [# of occurrences]) ÷ [Proposed Main footage] = [Risk Score]

4.2. A system risk assessment utilizing the risk model shall be performed each calendar year.

4.3. The risk model shall be validated based on Subject Matter Expert (SME) input and data.

4.4. Prioritization of replacement and mitigation footage may be adjusted based upon the following three categories:

4.4.1. Public Improvement

4.4.1.1. Coincident public improvement projects;

4.4.1.2. Right-of-way use restrictions or paving cut moratoriums;

4.4.2. Field Identified

4.4.3. Coordination with other Gas System Integrity replacement projects or coordination with replacing segments with the least impact to the cathodic protection system.

4.5. Re-evaluation of selected segments will occur on an on-going basis to incorporate new data.

Table 1. Older PE Pipeline Leak Frequency

FACTOR	YEARS SINCE LEAK REPORTED DATE	Leak Grade	Consequence	RELATIVE WEIGHTING
Leak Caused by Brittle Cracking or Fusion Failure	0 - 3	Grade A	HOS	0.2664
			NO HOS	0.1332
		Grade BA	HOS	0.1998
			NO HOS	0.0999
		Grade B1	HOS	0.1332
			NO HOS	0.0666
		Grade B2	HOS	0.05328
			NO HOS	0.02664
		Grade C	HOS	0.01332
			NO HOS	0.00666
	>3 – 4	Grade A	HOS	0.24
			NO HOS	0.12
		Grade BA	HOS	0.18
			NO HOS	0.09
		Grade B1	HOS	0.12
			NO HOS	0.06
		Grade B2	HOS	0.048
			NO HOS	0.024
		Grade C	HOS	0.012
			NO HOS	0.006
	>4 – 5	Grade A	HOS	0.2128
			NO HOS	0.1064
		Grade BA	HOS	0.1596
			NO HOS	0.0798
		Grade B1	HOS	0.1064
			NO HOS	0.0532
		Grade B2	HOS	0.04256
			NO HOS	0.02128
		Grade C	HOS	0.01064
			NO HOS	0.00532
	>5 – 6	Grade A	HOS	0.1864
			NO HOS	0.0932
		Grade BA	HOS	0.1398
			NO HOS	0.0699
		Grade B1	HOS	0.0932
			NO HOS	0.0466
		Grade B2	HOS	0.03728
			NO HOS	0.01864
		Grade C	HOS	0.00932
			NO HOS	0.00466
	>6 – 7	Grade A	HOS	0.16
		Grade A	NO HOS	0.08
		Grade BA	HOS	0.12
			NO HOS	0.06
		Grade B1	HOS	0.08
			NO HOS	0.04

FACTOR	YEARS SINCE LEAK REPORTED DATE	Leak Grade	Consequence	RELATIVE WEIGHTING
		Grade B2	HOS	0.032
			NO HOS	0.016
		Grade C	HOS	0.008
			NO HOS	0.004
	>7	Grade A	HOS	0.1328
			NO HOS	0.0664
		Grade BA	HOS	0.0996
			NO HOS	0.0498
		Grade B1	HOS	0.0664
			NO HOS	0.0332
		Grade B2	HOS	0.02656
			NO HOS	0.01328
		Grade C	HOS	0.00664
			NO HOS	0.00332
Leaks of Uncertain Cause, Having Cause Codes Consistent with Brittle Cracking or Fusion Failure	0 – 3	Grade A	HOS	0.1328
			NO HOS	0.0664
		Grade BA	HOS	0.0996
			NO HOS	0.0498
		Grade B1	HOS	0.0664
			NO HOS	0.0332
		Grade B2	HOS	0.02656
			NO HOS	0.01328
		Grade C	HOS	0.00664
			NO HOS	0.00332
	>3 – 4	Grade A	HOS	0.12
			NO HOS	0.06
		Grade BA	HOS	0.09
			NO HOS	0.045
		Grade B1	HOS	0.06
			NO HOS	0.03
		Grade B2	HOS	0.024
			NO HOS	0.012
		Grade C	HOS	0.006
			NO HOS	0.003
	>4 – 5	Grade A	HOS	0.1064
		Grade A	NO HOS	0.0532
		Grade BA	HOS	0.0798
			NO HOS	0.0399
			HOS	0.0532
		Grade B1	NO HOS	0.0266
		Grade B2	HOS	0.02128
			NO HOS	0.01064
		Grade C	HOS	0.00532
			NO HOS	0.00266
	>5 – 6	Grade A	HOS	0.0928
			NO HOS	0.0464
		Grade BA	HOS	0.0696
			NO HOS	0.0348
		Grade B1	HOS	0.0464

FACTOR	YEARS SINCE LEAK REPORTED DATE	Leak Grade	Consequence	RELATIVE WEIGHTING
			NO HOS	0.0232
		Grade B2	HOS	0.01856
			NO HOS	0.00928
		Grade C	HOS	0.00464
			NO HOS	0.00232
	>6 – 7	Grade A	HOS	0.08
			NO HOS	0.04
		Grade BA	HOS	0.06
			NO HOS	0.03
		Grade B1	HOS	0.04
			NO HOS	0.02
		Grade B2	HOS	0.016
			NO HOS	0.008
		Grade C	HOS	0.004
			NO HOS	0.002
	>7	Grade A	HOS	0.0664
			NO HOS	0.0332
		Grade BA	HOS	0.0498
			NO HOS	0.0249
		Grade B1	HOS	0.0332
			NO HOS	0.0166
		Grade B2	HOS	0.01328
			NO HOS	0.00664
		Grade C	HOS	0.00332
			NO HOS	0.00166
Reports of Large or Sharp Rocks in Pipe Bedding	NA	NA	HOS	0.00528
			NO HOS	0.00264

5. Older PE Pipeline Mitigation Categories

5.1 The mitigation categories shall be determined based on the following criteria except where SME review determines an alternate mitigation category is appropriate. Where SME's determine an alternate mitigation category is appropriate, the basis for this determination shall be documented for future reference.

5.1.5 Priority Replacement – Services that have had a brittle-like crack or fusion failure.

5.1.6 Scheduled Replacement – Pipeline segments with a risk/footage score of ≥ 0.0002.

5.1.7 Phased Program Replacement – Pipeline segments where one or more section has meet the Scheduled Replacement criteria and the data indicates a larger section should be replaced but does not meet the Scheduled Replacement criteria.

5.1.8 Suitable for Monitoring – Pipeline segments that are not in the first three categories but have experienced a fusion failure or brittle like cracking.

5.2 The mitigation categories and mitigation category thresholds may change as specified in Section 7.

6. Mitigation Plan

Table 2. Mitigation Plan

Mitigation Category	Mitigation Plan Description
Priority Replacement	Replace as soon as possible following identification.
Scheduled Replacement	Replace segment in the calendar year following identification as a Scheduled Replacement except where customer issues, permits, or other unusual circumstances prevent replacement.
Phased Program Replacement	Develop a phased plan to replace the larger segment considering the data. Document the plan and replace in accordance with the plan.
Suitable for Monitoring	Re-evaluate segment on annual basis. Perform normal operation and maintenance activities.

7. Measure Performance, Monitor Results, and Evaluate Effectiveness

7.1 PSE will measure the performance of older PE pipeline in each mitigation category to evaluate opportunities to refine the older PE pipeline risk model. This shall include tracking the following information and evaluating the trends:

7.1.1 The number of brittle like cracking and fusion failures on Older PE each year.

7.1.2 The footage of older PE pipelines replaced during the previous calendar year compared to the target footage.

7.1.3 The footage of older PE pipelines targeted for replacement for the current calendar year.

7.2 This data shall be reported in the Continuing Surveillance Annual Report and shall include a discussion of the trends and evaluation of the effectiveness of the older PE pipeline risk model.

7.3 If revisions to the older PE pipeline risk model and/or mitigation thresholds and actions are required, a plan for how PSE will proceed with making the revisions shall be included in the Continuing Surveillance Annual Report.

8 Records

8.1 Records summarizing the results of each annual risk assessment shall be maintained for 10 years.